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December 7, 2004

Mary L. Cottrell, Secretary
Department of Telecommunication and Energy
One South Station, 2nd Floor
Boston, MA 02202

Re: D.T.E. 04-70 — Petition of Boston Edison Company and Commonwealth Electric Company d/b/a NSTAR Electric for Approvals Relating to the Issuance of Rate Reduction Bonds Pursuant to G.L. c. 164, § 1H

Dear Secretary Cottrell:

Enclosed please find the responses of Boston Edison Company and Commonwealth Electric Company d/b/a NSTAR Electric to the record requests asked by the Department of Telecommunications and Energy and the Attorney General in the above-referenced proceeding, as listed on the following page.

Thank you for your attention to this matter.

Very truly yours,

John K. Habib

John K. Habib

Enclosures
cc: Service List
Joan Foster Evans, Hearing Officer (2)
Colleen McConnell, Assistant Attorney General (2)

RECORD REQUESTS

RR-AG-1
RR-AG-2
RR-AG-3
RR-DTE-1 **CONFIDENTIAL ATTACHMENTS**
RR-DTE-2 **CONFIDENTIAL ATTACHMENTS**
RR-DTE-3
RR-DTE-4
RR-DTE-6
RR-DTE-7

Record Request AG-1 (Tr. 1, at 23-24)

Provide a list of findings that the rating agencies would look for in a financing order.

Response

Attached as Attachment RR-AG-1 are rating agency sector criteria reports providing a general overview of the structural requirements and considerations for structured finance transactions such as rate reduction bond transactions. Although there are no published, comprehensive rating-agency criteria available, the Attachment RR-AG-1 describes the general criteria rating agencies use to evaluate rate reduction bonds. The structural elements incorporated into Exhibit NSTAR-1-B (draft Financing Order) that are not specifically addressed in Attachment RR-AG-1 are based on prior discussions by the Companies' and the state agencies' investment bankers and experience with the rating agencies.

STANDARD
&POOR'S

Structured Finance

Legal Criteria for U.S. Structured Finance Transactions

April 2004

The most recent version of this criteria is available at
www.standardandpoors.com/ratings/structuredfinance

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Legal Criteria for U.S. Structured Finance Transactions

Chapter Four:
Select Issues Criteria

Chapter Five:
Asset-Specific Criteria

Appendix III

Special Assets-Stranded Costs and Tobacco Settlement Revenues

Securitizing Stranded Costs

Electric utilities historically have enjoyed protected monopolistic status, in return for an obligation to provide service to the customer base whenever requested. In return, utilities have made significant long-term investments and entered into long-term power purchase contracts with the expectation that these would be recoverable through customer rates. In 1992, the enactment of the National Energy Policy Act introduced wholesale electric competition into the industry. Since then, almost half the states have taken steps toward a competitive retail market by legislating or ordering frameworks for "retail access," through which all customers will be able to choose their own electric generation supplier.

With a competitive market taking shape, many utilities have found themselves saddled with certain significant unrecoverable costs, generically known as stranded costs. These stranded costs are not new, but rather have already been approved by regulators and are incorporated in existing utility rates as part of traditional cost-plus regulation. However, if utilities are to compete in a deregulated market, they cannot pass these stranded costs along to customers. In many cases, the inability of a utility to recover a significant portion of these costs would result in significant financial deterioration, and in the worst cases, insolvency.

As noted, many legislatures and state regulatory commissions have established the means by which utilities can avert financial deterioration while also providing customers with lower rates. Asset-backed securitization is one such alternative. In several states, such as California, Pennsylvania, Massachusetts, Texas, New Jersey, Connecticut and Illinois, legislatures have enacted laws that enable utilities to finance the recovery of at least a portion of their stranded costs by issuing bonds backed by a statutory right to recover stranded costs. Standard & Poor's expects that there will be few, if any, additional states that will enact similar legislation that would also permit securitization of stranded assets.

In December 1997, the three California investor-owned utilities—Pacific Gas & Electric Co., Southern California Edison Co., and San Diego Gas & Electric Co.—securitized more than $6 billion of their approximately $28 billion of total stranded investment. During 1998, Illinois Power Co. securitized $864 million followed by Commonwealth Edison Co.'s $34 billion securitization transaction. In 1999, one Massachusetts utility and three Pennsylvania utilities completed securitization transactions. Boston Edison Co. issued $725 million of rate reduction certificates. PECO Energy Co. issued $4 billion, PP&L Inc. issued $2.42 billion, and West Penn Power Co. issued $600 million of transaction bonds. In 2000 and 2001, nine additional stranded cost securitization deals closed in states including Pennsylvania, Texas, Michigan, New Jersey, and Connecticut. For 2002 and 2003, six additional stranded cost securitization deals closed in states including New Hampshire, New Jersey, and Texas.

Utilities in states that have not yet addressed industry restructuring through legislative action or regulatory order, such as Indiana, Kentucky, Florida, and North Carolina, are generally low-cost producers with limited, if any, stranded assets. These states are much less motivated, therefore, to pursue industry restructuring, let alone securitization, at the present time. Whether or not these states ultimately pass relevant legislation, however, the relative competitive standing of their utilities will inevitably be diluted as high-cost utilities in other states shed a substantial portion of their high-cost assets through securitization.

Standard & Poor's believes that securitization of stranded costs is at least neutral, and generally positive for utility credit quality. The utility acquires cash up front, instead of receiving an increasingly at-risk revenue stream over time. Proceeds of the securitization are expected to be used principally to shrink a utility's total capitalization structure, including retiring debt that carries a higher coupon than that borne by the highly rated securitized bonds. In most cases, these interest savings are passed along directly to customers in the form of lower rates. Generally, the amount of rate reduction bonds that the utilities issued was designed specifically to generate a legislatively mandated rate reduction for customers.

Business and Legal Overview

What Are Stranded Costs?

Stranded costs are broadly defined to include any costs that were incorporated in the traditional regulatory cost-plus scheme that cannot be passed on to customers in a competitive marketplace. The most significant of these stranded costs are investments in high-cost nuclear and fossil plants. They also include deferred and capitalized operating costs, conservation and economic development expenditures, nuclear decommissioning costs, and long-term contractual obligations with high cost nonutility generators.

In the past, utilities constructed large, centrally located plants to gain economies of scale in producing electricity. Extremely long construction lead times and overly aggressive demand forecasts caused management to err on the side of oversupply to meet customer demand. Furthermore, the monopoly environment meant utilities lacked a strong incentive to contain costs. Indeed, the larger a utility's rate base was, the more investment on which the utility could earn a return. In addition, costs were exacerbated by circumstances. The last round of base-load construction occurred in the late 1970s and early 1980s, which was an era of high inflation and high interest rates. Finally, the nuclear incident at Three Mile Island in 1979 resulted in heightened Nuclear Regulatory Commission supervision, extending the timetable for plant completions and elevating capital costs significantly.

Since that time, new technologies have greatly reduced the cost of building generating facilities. Even more importantly, the economics of building smaller plants have continued to advance. The lead time for construction has been drastically reduced, from as much as 10 years to as little as 18 months. This reduction is in part due to the construction of much smaller-scale highly efficient plants. As a result, the cost of incremental generation today is significantly lower than the embedded cost of plant of most utilities.

The differential is most evident in nuclear plants. For instance, the 1,143 megawatt (MW) Nine Mile Point 2 nuclear plant, operated by Niagara Mohawk Power, was completed in 1988 at a cost of about $5,000 per kilowatt (kW), after a construction period of more than 10 years. This compares with a 500 MW gas-fired combined-cycle plant today that can be built in about 18 months at a cost of $450 to $550 per kW. While prudency hearings did lead to significant write-offs during the rate base proceedings of Nine Mile Point 2, the bulk of these costs were simply included in rates and are now being recovered from customers over a lengthy period of time.

Developments in Industry Environment

The enactment of the National Energy Policy Act of 1992 (NEPA) marks the beginning of the end of the last major government-protected monopoly. NEPA authorized the Federal Energy Regulatory Commission (FERC) to mandate that utilities become open-access common carriers for wholesale electric sales, known as wholesale wheeling. Wholesale sales are bulk power sales between utilities or between a utility and a third-party producer. If two utilities are not interconnected, they would need access to a third party's transmission network to complete such a transaction.

The ability of a utility to sell power to an end user that is not within its franchise service territory, or the sale of power from an independent power producer to an end user, is called "retail wheeling." Currently, utilities are not permitted to engage in retail wheeling. However, retail customers, aware that there may be cheaper power sources than their current supplier, are pressuring state regulators to permit them to buy power from alternative suppliers. While most regulators agree that competition will lower the price of power, some assert that the objective is not merely to lower rates, but to provide customers with the option to choose their power provider.

The vast majority of utilities and regulators concur that retail wheeling is inevitable, so states have had to grapple with how to make the transition from a regulated to a competitive environment. As mentioned earlier, almost half the states have passed laws to phase in direct access to all customers. Most, though not all, of these legislative initiatives include securitization of stranded costs as a means of reducing utilities' financial exposure to a competitive retail environment.

Recovery of Stranded Costs

Vertically integrated electric utilities provide customers with three basic functions: generation, transmission, and distribution. Because of legal, regulatory, and technological advances, generation no longer displays monopoly characteristics. Transmission and distribution, or the "wires" function, on the other hand, will likely remain natural monopolies for the foreseeable future since it would be prohibitively expensive, and environmentally difficult, to construct redundant wires. Transmission consists of the high-voltage system that moves power in bulk from generating plants to an electric distribution system or a load center. Distribution receives stepped-down power, which is then transported at lower voltages to individual end users.

As part of various state legislative initiatives, utilities are being required to functionally, if not legally, disaggregate the vertically integrated components of their business. The costs of each function will be determined and itemized, or "unbundled," on customers' bills. While customers may purchase the actual electrons from a source other than their local utility, they must continue to transport this power over the distribution wires owned by their local utility. The local utility will use its wires system to charge customers for the services it provides, which will include transmission of power bought from other suppliers. Other services, such as billing and metering, could be maintained by the utility or could be opened to competition as well. Any stranded cost that is identified, isolated, and by mandate recoverable in utility rates, will also be recovered as a "wires charge;" it cannot be recovered as part of a generation charge, since customers may purchase generation from an alternative source.

Stranded costs, which have been realized as such only with the prospect of a competitive market, are included in current utility rates, but they are being amortized over as long a period as 30 to 40 years. Utilities need to accelerate the recovery of these above-market costs as quickly as possible if they are to lower their rates in preparation for a competitive environment.

Statutory Securitization of Stranded Costs

Until now, securitization of stranded assets has been made possible by state statute. In general, such statutes provide that the stranded assets themselves, plus interest on any bonds backed by stranded assets, the costs of servicing the bonds, and the costs of bond issuance all be collected through imposition of a tariff that is collectible from the utility's customers. While differing in particulars, the legislation in Pennsylvania, California, Illinois, Massachusetts, Texas, Connecticut, New Jersey, and elsewhere shares certain characteristics that are significant from a rating perspective.

The statutes specifically provide for securitization of the stranded costs through their sale to a financing subsidiary and ultimately, to a trust that issues the bonds. The statutes award true sale status to the transfer of the stranded assets to a finance subsidiary. This should help support the legal conclusion that the transfer constitutes a true sale for bankruptcy purposes.

The statutes also provide that any proposal for a securitization of stranded assets be approved on an irrevocable basis by the relevant utility regulatory commission. The commission must set a tariff schedule. A tariff would be included in the ordinary bills sent to customers, and would amortize the stranded assets over the life of the proposed securitization. The tariff would be a separate itemized charge on the customer's bill, and could be either a fixed charge or tied to electricity usage, in either case included in the utility's wires charge. In scheduling the tariff needed to amortize the assets fully, the commission will take into account the utility's forecast regarding the projected size and demographics of its customer base. Where the tariff is tied to electricity usage, predicted customer usage will be important.

The tariffs that are actually collected from customers may fall short of what was originally anticipated. In addition to defaults in bill payments, the customer base might decline due to economic and/or technological factors, or usage might vary from what was originally predicted. This might happen, for instance, if the winter is unusually warm or the summer particularly cool. These are credit risks that could impact the ability of the tariff to amortize the assets fully.

To address these risks, the legislatures have created a statutory form of credit support, known as the "true-up" mechanism. The statutes provide that the utility periodically apply to the commission for a readjustment of the tariffs. The commission must then readjust the tariffs charged to customers, so that the bond amortization schedule is met. This minimizes credit risk, except at the tail end of the transaction after the final true-up has occurred. Liquidity risk will, of course, exist during the periods between true-ups, to the extent that collection shortfalls occur.

The true-up mechanism also may effectively minimize prepayment risk. While there may be a tariff collection shortfall, it is also conceivable that excess collections may be received. This might occur, for example, if the customer base grows at a greater rate than originally anticipated when the tariffs were established. If collections exceed expectations for a particular period, the true-up mechanism could potentially reduce the remaining tariffs accordingly, so that the remaining transaction amortizes as scheduled.

When the utility applies for a true-up, the commission may not grant it immediately. The commission's delay will add to liquidity risk, because the shortfalls in collections to be remedied by the true-up will last for a longer period, until the commission finally grants the true-up. A delay by the commission will not create credit risk during the transaction, because once the true-up is in place, the adjusted tariff will take into account any collection shortfalls caused by its delay. But a delay in the true-up could result in a credit loss at the tail end of the transaction. The commission might take so long to grant the true-up that the final true-up never occurs. The statutes prevent this potential credit loss, as well as limit liquidity risk caused by a delay, by setting a deadline for implementation of the true-up. For example, California requires that the commission implement a true-up within 90 days of each anniversary date of the transaction. Other statutes simply require true-up filing, with the commission, to become effective as early as the subsequent month.

The duration of these transactions and the ability to impose true-up periods and tariff collections indefinitely depend initially on whether the statutes impose a limit on how long the tariff may be collected from the utility's customers. Even where no limit is set as a statutory matter, the final true-up period, and the deadline for tariff collection, will depend on the legal final maturity date set for the bonds.

A utility might change hands for some reason, or file under Chapter 11 of the U.S. Bankruptcy Code. Such an event could strike at the heart of a potential securitization. Stranded assets will not be recovered unless the utility continues to provide electricity, bill its customers, transfer the tariff to the securitization trust, and apply for true-ups when necessary. The statutes address this problem by requiring that any successors to the utility, whether through bankruptcy, merger, or sale, must perform all of the utility's obligations in connection with the securitization.

The statutes provide another feature, by providing that, contrary to what would usually occur under the Uniform Commercial Code (UCC), there is a continued security interest in collections that have been commingled with other funds of the utility. This eliminates the usual credit risk associated with commingled funds in the event of a bankruptcy of the utility, although it fails to alleviate the liquidity risk and potential credit risk caused by the automatic stay *(see Appendix III, Special Assets-Stranded Costs and Tobacco Settlement Revenues, section on Protection Against Credit Risk Caused By Commingling)*.

Finally, the statutes purport to create new property interests that must be perfected in a manner different from a UCC security interest. However, there is the possibility that stranded assets might still be considered subject to the prior lien of existing mortgage bonds. As a result, proceeds of the securitization might need to be applied to pay down the debt secured by the prior lien. This would, in any event, be positive from a credit perspective, because the bonds being retired (typically general obligation bonds bearing the rating of the utility) would have a higher interest rate than the 'AAA' rated securitized bonds used to retire the obligations.

Significance of Statutory Securitization

To date, stranded cost securitizations rated by Standard & Poor's have been based on legislation promulgated specifically for that purpose. Nevertheless, Standard & Poor's understands that, as a regulatory matter, state public utility commissions have, de facto, historically permitted recovery of stranded costs through rate adjustment.

While public utility commission regulatory action may well be sufficient to accomplish a securitized recovery of stranded costs, Standard & Poor's believes that there may be certain advantages to a legislation-backed securitization. Statutes have the benefit of having undergone the political process. Affected interests are given the opportunity to introduce, and argue for, their respective views. Hearings, drafting and amendments, floor debate, and overall legislative, and press and public scrutiny constitute the process by which political compromise is achieved and consensus built. The political process is viewed as investing the resulting legislation with a considerable degree of stability and support.

Viewed from the perspective of legal capacity, legislation has other advantages. At the heart of stranded cost securitization is the creation of a property right in the transition charges that serve as the basis for debt service. While it is clear that state legislatures are empowered by due process of law to create property rights, and to define and record how these rights are to be enjoyed, the ability of a state public utility commission to achieve the same end by regulatory compact may not be as certain.

Statutory status provides both constitutional and political protection against the risk that the creation and pledge of securitization property might be impaired by subsequent amendment. Historical precedent indicates that a legislature is unlikely to reverse itself once it has enacted a statute. Even if a political reversal were to occur, the Pennsylvania, Massachusetts and California statutes recognize that the bondholders possess certain constitutionally protected rights. Both statutes provide that if the right to recover stranded assets is compromised in any way, the bondholders are entitled to adequate compensation.

Nevertheless, in jurisdictions where public utility commissions may reasonably be viewed to have the capacity and authorization to order a recovery of stranded costs through a securitization-type procedure, and in which the commission has a stable history of consistent regulatory action, and in which the courts have paid regular deference to commission order, Standard & Poor's will consider regulatory-based recovery procedures case by case. However, any such consideration will necessarily involve a comparison by Standard & Poor's of the proposed regulating action and its enactment in contrast to rated, statute-based recovery plans.

Overview of Stranded Cost Securitization

Differences From Traditional Asset-Backed Transactions

Several key aspects differentiate the securitization of stranded costs from the securitization of more conventional asset types.

Cash Flow Receivables

In a typical securitization, the originator of the assets transfers a pool of receivables to a trust and receives payment based on an agreed-upon value for those receivables. The key in this case is that the receivables have already been created. In contrast, stranded assets are not traditional receivables. Although the statutes create a present property right to future collection there is no initial cash flow backing the debt. Stranded assets represent the present right to the cash flow from receivables that will be created in the future when performance, in this case power generation and delivery, has been provided. But until this performance by the utility company takes place, the customer is not obligated to make any payments. Power generation is thus critical to assure full and timely payment to securityholders. As a result, there is a greater dependence on the utility as seller/servicer to do more than just collect payments on existing receivables and liquidate collateral to the extent needed.

Dependence on Servicer

Servicer bankruptcy filings generally cause a change in servicer in most asset-backed transactions to prevent any disruptions in the required servicing and collections on the portfolio. Therefore, a substitute servicer must be ready and willing to take over all servicing responsibilities, if necessary. But unlike in typical securitizations, the transaction cannot fully rely on a substitute servicer. A utility does not just collect payments; it must continue to provide power.

Because provision of electricity is fundamentally a necessary service, however, Chapter 7 liquidations are unlikely. In contrast, utilities will continue to operate in Chapter 11 reorganization, and thus, provide power and enforce collection from customers. Security is provided by the statutory mandate that collection obligations must be assumed by any successor corporation, including successors pursuant to reorganization, or otherwise. Due to the regulated nature of the industry a state-by -state review of successor servicing arrangements will be performed by Standard & Poor's.

True-up as Credit Support

Credit support is entirely structured within the finances of the typical securitization. In contrast, in these transactions credit support has been provided by the statutory true-up mechanism. The parties must initially come up with a proposed amortization schedule. This schedule determines the tariff to be charged to recover the stranded costs, as well as the costs of the securitization itself. In setting this tariff schedule, the utility makes certain assumptions about charge-offs and sales over the following year or even decade.

These assumptions will necessarily be inaccurate, especially as the date of forecast becomes increasingly remote. As a result, the stranded costs collected from customers could be less than those needed to pay off the bonds. The true-up addresses this risk. The statutes provide that the utility periodically apply to the commission for a readjustment of the tariffs. The commission must then readjust the tariffs charged to customers. This effectively eliminates credit risk, except in the tail end of the transaction after the final true-up has occurred.

It should be understood that the true-up is not quite the same thing as an unlimited cash collateral account. Because the true-up will only be as good as collections in the following year, the amount of a current year's shortfall will not be fully recovered in the next year, due to charge-offs and forecast error occurring in that year. However, the amount will decrease over time as successive true-ups are implemented. Where statutes do not place a limit on the tenor of the bonds and permit indefinite true-ups, the legal final maturity can simply be extended as a structural matter to gain the benefit of additional true-ups. This allows for as many true-ups as necessary to reduce the shortfalls that cannot be collected because they occur in what may have been originally contemplated as the final year of the transaction.

The true-up can make the amortization schedule for the bonds more predictable, unless dramatic consumption changes occur. This is because the true-up may adjust the amount payable to the trust by the customer base to the extent that there has been a shortfall or surplus in the prior period.

Protection Against Credit Risk Caused by Commingling

In the event of a bankruptcy of the utility, any tariff collections that are commingled with the utility's funds will be trapped by the automatic stay provisions of the Bankruptcy Code and ultimately may be lost to the transaction altogether. To reduce this liquidity and potential credit risk, a ratings trigger typically will be required that provides for reduction in the permitted commingling period to the extent that the utility has been downgraded. This effectively minimizes the amount of cash that may be commingled and, therefore, lost.

The statutes provide that properly perfected liens held by the securitization trustee will extend to commingled funds. Therefore, structural limitations are not necessary to limit credit risk. Nevertheless, due to the automatic stay, there may be a delay in receipt by the trust of the funds, so usual Standard & Poor's criteria regarding commingling will continue to apply *(see Appendix III, Special Assets-Stranded Costs and Tobacco Settlement Revenues, section on Commingling by Servicer).*

Perfection Mechanisms

As stated above, the statutes provide for their own methods and location for filing and perfecting stranded assets. This may or may not result in the conclusion that stranded assets are new property interests not subject to UCC filing and priority rules, and thus are not subject to prior liens under the UCC.

Overcollateralization as Additional Credit Enhancement

As mentioned earlier, the true-up mechanism will play an integral role in the transaction structure. The frequency of the true-up, for example, will influence the need for additional credit enhancement. Overcollateralization is the most likely form of credit support. Overcollateralization would cover the risks in the stub period following the final true-up, as well as make up for past shortfalls in collections that were never fully trued-up in the past.

Sale Accounting and FAS 125

Stranded cost securitizations do not possess sale status as an accounting matter under FAS 125. The Security Exchange Commission's Office of Chief Accountant has indicated that while the utilities may be able to sell the right to recover stranded costs as a legal matter, they will not be able to remove the assets (and associated debt) from their balance sheets under FAS 125. Nevertheless, as long as the transaction is structured as a true sale for legal purposes, Standard & Poor's will "back out" for analytical purposes nonrecourse debt and associated carrying costs from the utility's consolidated financial statements. While off-balance-sheet treatment would have enabled a more clear-cut analysis, Standard & Poor's will attempt to recognize the economic (as opposed to the accounting) reality.

Debt for Tax Treatment

Any utility intending to securitize stranded costs will likely seek a private letter ruling from the IRS that states that the sale of the assets constitutes a "debt for tax transaction." In other words, the sale would not result in the immediate recognition of income. If the sale were deemed to provide immediate income, the utility would incur an immediate tax liability as well. This would destroy the economics of a securitization.

The Rating Approach

Specific credit and legal risks that arise in securitizing stranded costs are addressed below. Standard & Poor's pursues a general rating methodology that attempts to stress in cash flows the ability of the true-up mechanism to ensure timely payment of interest and repayment of principal. In addition, it attempts to determine the number of true ups needed to meet these payments, that is, the structure's ability to meet its legal final maturity.

Credit Risks

Inaccuracy in Forecasting

As mentioned earlier, the funds necessary to pay the stranded assets of the issuer are dependent on the tariff set by the commission and collected from the utility's customers. Tariff schedules are compiled for each customer class so that, taken together, the tariffs charged will amortize the stranded assets over the life of the securitization, while making timely interest payments. The tariff amounts themselves are based on estimates of cash flows to be collected from the customer base. The tariff amounts are thus determined based on such factors as the utility's forecast of population growth or decline, and seasonality in expected usage.

A shortfall in tariff collections can be caused by a number of factors:

- Unanticipated customer migration (anticipated migration is included in the forecasting). Residential and small business customers are considered low risk in terms of customer migration. Large industrial customers, on the other hand, are considered a significant risk that requires additional stress to the cash flows *(see Appendix III, Special Assets-Stranded Costs and Tobacco Settlement Revenues, section on Cash Flows).* Additionally, as the term of transition bonds issued exceeds 6-8 years, technology based customer migration increases significantly and begins to impact wage usage from commercial and small business customers.

- Unanticipated weather conditions. Seasonal weather fluctuations are studied, and typically accounted for in setting the tariff charge.
- Lower-than-expected usage. Forecast error negatively impacts liquidity on the bonds and "pushes out" the maturity of the bonds by requiring additional true-ups before the bonds can be paid out. To capture this risk, historical forecasting error is stressed at a certain multiple depending on the rating sought.
- Where the tariff is recoverable from large industrial and commercial customers, Standard & Poor's will require data stratifying these customers by revenues generated. The cash flows will be additionally stressed to account for a potential loss in revenues caused by relocation of those customers with a high concentration risk in revenue generation for the utility.

Certain states have legislated rate caps on either the transaction charge for specific customer classes or on the total customer charge (i.e., through mandated rate reductions). Standard & Poor's will review the cash flow models to confirm that these rate caps are respected in stress scenarios.

Higher-Than-Expected Charge-Off Experience

Like other forecasting variables, anticipated charge-offs are included in forecasting for purposes of setting the tariffs. Charge-offs may be higher than expected based on historical experience due to a variety of factors, including economic changes and unforeseen disasters. To account for this risk, charge-off history is stressed by the multiple relevant to the rating sought.

Commingling by Aggregators

The recent mandated unbundling of generation, transmission, and distribution charges has paved the way for alternative generation suppliers. The consumer may choose to purchase its generation services from an alternative supplier, while continuing to pay transmission and distribution (wires charge) to the utility. As discussed earlier, the tariff would be included in the wires charge, so that collection of the tariff itself would not be endangered by the existence of competition for generation services. However, commingling risk could exist as a result of potential billing arrangements for the utility's transmission and distribution services on the one hand, and the alternative energy provider's generation services on the other.

Generally, alternative energy services providers (retail electric providers; third-party servicers) may provide a consolidated bill for their generation services and the tariff owed to the utility. Where this is the case, the energy services provider is liable to pay the tariff regardless of whether it has received collections from the ultimate users. As a result, the securitization is exposed to commingling risk, and the resulting loss of commingled tariffs, in the event of the bankruptcy of an energy services provider.

This risk can be mitigated by certain restrictions on the length of time that an energy services provider may commingle funds before consolidated billing and service is terminated. If the energy services provider becomes delinquent, direct and consolidated billing may cease and service and separate billing to the end-user customer would be made up for the tariff. This means that the aggregator could commingle funds for a number of days before consolidated billing were terminated. To address this risk, in several rated securitization transactions, Standard & Poor's cash flows eliminated one month of collections per year at the utility's peak billing cycle.

This or other risks involving alternative energy providers may exist in other stranded cost securitizations. Standard & Poor's will assess these risks and the resulting necessary cash flow stresses on a case-by-case basis.

Estimate of Tariff Based on Collections Curve

Generally, utilities are unable to allocate amounts received to various charges on the bill, so they were unable to calculate what percentage of collections constituted tariff collections. To address this problem, the utilities prepared forecasts of the percentages of amounts expected to be received during each of the following six months. These forecasts were based on collections curves developed periodically based on accounting studies and collections studies performed by the companies. For each monthly billing period, collections were estimated over six months based on the collections curve.

When the actual tariff remittances by customers are calculated (on the seventh month following each monthly billing period), either too much or too little may have been paid for that billing period. If the amount remitted has been less than the actual tariffs collected during that six-month period, the shortfall will be made up the following month out of the servicer's (the utility's) own funds. Thus, if the servicer is bankrupt (Standard & Poor's assumption), there is a risk the bondholders will lose that portion of the tariff. If the actual tariff amount has been less than the estimated tariff collections remitted to the trust, the servicer would be entitled to withhold the excess amount paid from the next month's remittances.

It is not clear whether this risk will be present in other securitizations. To date, the risk of lower-than-actual remittances has not been separately stressed in the cash flow runs. The one month of lost collections *(see Appendix III, Special Assets: Stranded Costs and Tobacco Settlement Revenues, section on Commingling by Aggregators)* has been sufficient to cover this risk. Standard & Poor's also has relied on data provided by the company showing relative lack of volatility in the collections curve.

Commingling by Servicer

Several utilities in the stranded cost securitizations possessed ratings of 'A-1', which allow them to commingle collections for one month. Transaction documents specify that if the rating drops below 'A-1', the allowed commingling period will switch to two days, in accordance with Standard & Poor's criteria regarding loss of collections due to commingling risk. In all cases, the rating of the utility will determine the period of permitted commingling of funds before transfer to the trust.

Higher Tariff

An increase in tariff resulting from higher true-ups might become burdensome to consumers. This risk might have a spiraling effect, because greater charge-offs or customer migration or decreased usage might result, which in turn would result in the need for increased true-ups. Standard & Poor's will assess this risk by examining the highest per kWh tariff charge reached under the relevant stress scenarios. This risk increases as the term of the transaction increases to 10-15 years given greater technological/migration risk.

Cash Flows

Two cash flow runs are generally required in rating stranded costs: a compounding forecast error run and an oscillating forecast error run, implementing the stress scenarios described below. These runs are created to test liquidity as well as the transaction's ability to meet its final maturity. They do so by creating scenarios where the true-up in the tariff amount (the reset of the tariff to reflect prior experience with actual collections and recover prior shortfalls in collections) continuously fails to reflect actual collections.

Compounding Forecast Error Run

The compounding forecast error run assumes a compounding stressed error in forecasting resulting in a continual decline in actual tariff collections over what was forecast for that year. Assume, for example, that during year one, sales are 90% of the original sales forecast, that is, forecast error reflecting a multiple of the average forecast error for the customer class, where actual collections are less than expected collections.

At the end of year one, the tariff charge is recalculated assuming that year two customer sales will be what was experienced in year one, that is, 90% of the original expected forecast. Instead, year two sales are only 81% (90% multiplied by 90%) of the original sales forecast.

The sales decline is generally based on a multiple of the greatest historical nonnormalized, absolute value, forecast variance by customer class. This compounding is assumed to continue from year to year over the life of the transaction.

Oscillating Forecast Error Run

The oscillating forecast error run assumes a scenario where in one year tariff collections exceed expectations, so that in the following year, the tariff is reset based on the prior year, only to experience a shortfall in actual collections. Assume for example that the appropriate stressed forecast error is 10%. During year one, sales are 90% (10% below) the original sales forecast. At the end of year one, the tariff is recalculated assuming that year two sales are also 90% of the original forecast. Instead, year two sales are 99% (110% of 90% level) of the original forecast. The tariff for the following year is reset assuming 99% of original forecast collections, only to receive 90% of originally forecast collections. This oscillation between 90% and 99% of original forecast is assumed to continue over the life of the transaction.

Legal Final Maturity

The legal final maturity dates on stranded cost transactions are often set at two years beyond expected maturities. This additional period acknowledges the long-term nature of the liabilities being rated, and the corresponding possibility that fundamental changes in technology might take place that further stress the transaction in an unforeseen manner. One currently known possibility is that over time customers may increasingly switch to self-generation, which would enable them to cease paying the wires charge and thus, the tariff. Certain transactions have reduced this period by requiring more frequent (e.g., monthly) true-ups during the final year or two of the transaction.

Legal Risks

Reliance on Commission to Implement True-Up, and Potential Delay in Approving the True-Up

Standard & Poor's believes that so long as the statute clearly specifies the maximum period before which the commission is compelled to implement the true-up, any shortfall in collections resulting from the delay can be sized and factored into the cash flow projections. Certain structures may permit the application of principal collections as liquidity for any interest payments due to noteholders during any true-up delay. In the absence of such features, adequate provision for liquidity and additional credit support should be demonstrated to Standard & Poor's.

Adequate Provision

Law permits alteration or limitation of right to transition property and right to collect tariffs if "adequate provision" is made to the bondholders. Although there has been no conclusive demonstration as to what constitutes "adequate protection," and how such alteration or limitation would affect timely interest and principal payments on the bonds, Standard & Poor's, in rated transactions, has received legal assurances that any such alteration would be constitutionally prohibited were it substantially to impair the security for the bonds. While such assurances do not really define adequate provision, Standard & Poor's believes, in practice, that adequate provision should prove to be the functional equivalent of the pledged transition property.

Stranded Assets to Aid Industry Restructuring

Securitization of stranded assets provides an efficient method electric utilities can use to quickly free themselves from the high cost of stranded assets that prevents them from becoming players in the emerging competitive retail generation market. At the same time, the statutory true-up mechanism provides strong credit support that has withstood 'AAA' stress criteria applied by Standard & Poor's.

FITCH IBCA
The International Rating Agency

Utility Stranded Costs: Rating the Securitization of Transition Tariffs

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This report updates Fitch IBCA Research on "Guidelines for Rating Debt Backed by Regulatory Assets," dated Sept. 30, 1996, available on Fitch IBCA's web site at www.fitchibca.com.

■ *Overview*

In December 1997, the three California investor-owned utilities each completed a securitization through the issuance of debt backed by the right to collect "transition tariffs." Across the U.S., investor-owned utilities in several states, including Illinois, Pennsylvania, and Montana, are poised to issue similar bonds with legislative support. The development of this asset-backed market has tracked the timing of electric industry restructuring, subject to the legislative and political process in each state. The earliest transaction of this type was completed in July 1995 by Puget Sound Power & Light Co. (now known as Puget Sound Energy), which sold the right to collect tariffs relating to energy conservation programs. In 1996, bonds backed by utility surcharges were issued by Spanish and Italian utilities, with additional governmental support. The California transactions have been viewed as setting precedent for broader issuance in this market.

The U.S. electric utility industry is undergoing a fundamental reorganization, under which power generation will become subject to competition while transmission and distribution will remain monopoly activities. As part of this transition, many utilities are requesting compensation for prior investments or commitments that were deemed prudent by investors and would be rendered uneconomic in a competitive market. These investments, commonly referred to as "stranded costs" or "transition costs," may include unrecovered investments in, or costs associated with the closure of, a power plant; maintenance costs of nuclear power facilities; nuclear decommissioning costs; obligations associated with above-market power purchase contracts; the cost of work force retraining; and demand-side management or low-income assistance programs.

In many states, as a matter of public policy, the legislature and regulatory authorities have provided for recovery of utilities' stranded costs through the imposition of a defined surcharge or tariff to be assessed by the utility against its customer base. The resulting right to collect future tariff revenues from utility customers is referred to herein as "transition property."

In states considering securitization, a statute will contain general securitization guidelines that will be supplemented by specific applications for financing orders submitted by the utilities to the state utility commission. The goal of securitization is to reduce the utility's cost of capital, thus improving its ability to operate in a competitive market, and to allow utilities to realize compensation for stranded costs sooner.

It is important to note that statutes establishing transition tariffs will not necessarily provide for the securitization of such tariffs. Furthermore, securitization is only one method of recovery for stranded costs. Many utilities have chosen to recapitalize through divestiture of assets or other forms of reorganization. Also, securitization need not be directly coupled with the identification and compensation of stranded costs. For example, the restructuring statute passed in Illinois permits securitization of a defined transitional revenue stream, without linkage to stranded investment.

Several features differentiate debt backed by transition tariffs from "plain vanilla" asset-backed debt instruments. The establishment of transition property (i.e. the right to collect the future cash flow stream) will depend on a specific statute or body of regulatory procedures rather than standard contract law, such as the Uniform Commercial Code (UCC). Transition property represents a dedication of future revenues; consequently, the creation of the obligation to pay depends on the performance of a service to be rendered in the future. Furthermore, individual utility ratepayers may move into or out of the region or existing customers may increase or reduce their consumption, thereby increasing or reducing overall payments for energy delivery. Final maturities on these bonds may stretch out 10–15 years. The longer the expected maturity, the greater the potential impact business or technology changes could have on the cash flows supporting the bonds.

Key Rating Elements

- ☐ Legal and Regulatory Framework
- ☐ Political Environment
- ☐ Transaction Structure
- ☐ Analysis of the Utility as Servicer
- ☐ Credit Analysis
- ☐ Regional Economic Factors
- ☐ Cash Flow Stress Cases

Legal and Regulatory Framework

Unlike other asset classes, the tariff-based cash flow stream supporting the bonds is established by legislative or regulatory authority. Thus, the first component in Fitch IBCA's analysis is a thorough understanding of the authorizing legislation and financing orders.

The enabling statute or order will generally provide for the restructuring of the state's electric utility industry by bringing competition to electric generation and, in some cases, certain other utility-related services (e.g. metering, meter reading, and billing).

In states considering securitization, a transition tariff will be established through a statute approved by the state legislature, or by regulatory order approved by the state utility commission, to provide for the recovery of a portion of utilities' stranded costs. It is important to note that utility restructuring legislation (enacted to introduce competition to the generation market) may establish transition tariffs while not allowing for securitization. Some legislation, as in California, provides for securitization of only a portion of the transition charge.

For a ratable securitization, the transition tariff should provide various legal elements that are crucial to the securitization, as detailed in the following sections.

Property Right: Since the asset securing the bonds is a right to a future cash flow stream, the statute or order should establish the future tariff collections as a property right that can be transferred and pledged as a security interest. The transition property will not be governed by the UCC; therefore, the procedures for establishing a first-perfected security interest should also be outlined in the statute or order. The amount of the tariff, as well as the rules for its collection, will be defined in financing orders approved by the regulatory commission in the relevant state.

Irrevocability and State Support: The statute or the regulatory order must establish the transition tariffs as irrevocable, prohibiting the legislature, the commission, or any other agency or governmental entity from rescinding, altering, or amending the tariffs or transition property in any way that would reduce or impair their value. The irrevocability language is an important protection against changing political agendas in the legislative or executive branches of government. Once the bonds have been issued, the tariffs are further supported by the "contracts" and the "takings" clauses of the U.S. Constitution and most state constitutions, which protect against impairment of contracts and taking of property without the provision of adequate compensation.

If the bonds are issued pursuant to specific legislation, the statute will generally contain a state non-impairment pledge, wherein the state agrees that it will not limit or alter the tariffs, transition property, financing orders, or any other right under the bonds until the principal of and interest on the bonds are fully paid or unless adequate compensation has been made to safeguard bondholder rights.

Because the assets securing these bonds are created through the political process and are bound with industry restructuring, the enabling statute and orders will be subject to challenge from opposing parties. While the political process differs from state to state, the enactment of legislation, or issuance of a final commission order, involves a process in which interested parties have the opportunity to challenge or submit amendments to the proposed language. Generally, after a statute is approved by the legislature, and/or an order is issued

Examples of Stranded Costs/Transition Costs

- ❑ Above-Market Generation — Nuclear or other generating facilities that will not be cost effective in a competitive environment.
- ❑ Non-Utility Generating or Independent Power Contracts — Many of these contracts have been signed with fixed or escalating power prices above current and estimated future power sales prices.
- ❑ Regulatory Assets/Social Programs — Catch-all category for deferred charges, nuclear decommissioning costs, conservation programs, employee retraining, and low-income customer subsidies.
- ❑ Transaction Costs — The costs of issuing, servicing, and retiring bonds.

by the commission, there is an additional defined period when outside parties can challenge the statute or order through litigation. When this period has expired, the potential for later attack is substantially diminished.

Many states have a ballot initiative process that allows opposition groups to place a petition on the election ballot upon receipt of a given number of voter signatures. When analyzing bonds issued under statute in these states, it is important to ensure the soundness of the federal and state constitutional protections, the irrevocability language, and the state non-impairment pledge. Fitch IBCA analyzes the constitutional protections and issues in each state and requires corresponding legal opinions from utility counsel. In addition, other qualitative factors, such as capital market restrictions, political support, the potential legitimacy of any legal attack, and incentives of all parties involved, should be considered.

Nonbypassability: The transition tariff is usually assessed as a distribution charge, applicable to the monopoly utility service. Therefore, regardless of which power provider generates the energy delivered to the customer, a transition charge will be collected based on delivery service. This type of tariff is frequently referred to as a "wires charge." While customers will be able to choose their power provider, their need to be connected to the distribution system, whether for primary or backup service, will limit their ability to bypass the tariff.

Bankruptcy Remote/True Sale: The statute or regulatory order should protect the bondholders from the interruption or impairment of cash flows in the event of a utility bankruptcy. It should also ensure that the transfer of the transition property will be treated as an absolute transfer, not a pledge, of the seller's right, title, and interest in the property. The statute or regulatory order should also define conditions for a valid, enforceable, and perfected security interest for the indenture trustee.

Fitch IBCA requires legal opinions of utility counsel stating that, in the event of a utility bankruptcy, the transfer of the transition property would constitute an absolute sale rather than a pledge. Thus, the transition property is not considered part of the utility's bankruptcy estate and the court will not order the consolidation of the assets of the special purpose vehicle (SPV) with the utility in the event of the utility's bankruptcy.

True-Up Mechanism: The statute or order may provide a mechanism that would authorize the utility to reset tariffs at least annually. The reset, referred to as the "true-up mechanism" or "true-up," typically adjusts the tariff to a level sufficient to maintain interest payments, scheduled principal amortization, related fees, and any credit enhancement balances. The statute or order may provide for more frequent resets, based on the occurrence of certain events, such as a minimum percentage variance between projected and actual principal amortization. The true-up can increase or decrease the tariff depending on the positive or negative variance of actual tariff payments and/or energy consumption from the utility's projections.

The filing for the true-up mechanism will generally be made with the utility regulatory commission or equivalent agency of the state based on updated sales forecasts for the forthcoming years. It is important that the statute or order neither require discretionary commission approval for the true-up

Legal and Regulatory Framework Checklist

- ❑ Establish transition tariff as a property right.
- ❑ Nonbypassable for any customers connected to the distribution system within the service territory.
- ❑ Irrevocable by subsequent legislatures or commissions; statutory language (if applicable) should include state non-impairment pledge.
- ❑ Supported by federal and state constitutional protections.
- ❑ Bankruptcy-remote issuer, nonconsolidation of assets with the utility, and a true sale of the transition property.
- ❑ Granting of a first-perfected security interest in the transition property to the indenture trustee.
- ❑ Review of requirements and mechanics of true-up mechanism (if applicable).
- ❑ Guidelines for consolidated billing by third-party energy providers (if applicable).

Administrative Securitization

Utility securitizations, to date, have been preceded by passage of legislation that explains the transactions' legal and structural framework. As detailed in this report, the key provisions included in a securitization statute relate to the irrevocability of a commission finding creating the transition tariff that underlies the securitization, the true sale of the utility's transition property to a special purpose vehicle (SPV) or trust, and the remoteness of the SPV or trust from the potential bankruptcy of the involved utility or any entity acting as servicer for the transaction.

It is possible that a valid securitization could be structured without the need for such specific legislative authorization. This technique, called "administrative securitization," seeks to ensure the necessary elements described above based on existing state law or constitutional provision. The idea has received the greatest consideration in states where the legislature has found the enactment of a more traditional authorizing statute to be difficult (New York), or where the utility regulatory commission receives its authority from the state constitution and, thus, is shielded from any attempt by the legislature to limit the commission's powers or modify its decisions (Arizona).

In the absence of specific enabling legislation, the parties formulating an administrative securitization must rely on the general powers granted to a public utility commission under existing law. Accordingly, the transaction structure might differ depending on the specific legal circumstances of the state in which the transaction will occur. Regardless of the form of a particular deal, its legal bases will likely be underpinned by one or more of the following legal theories that would hold that future action by either the commission or the legislature to adversely affect bondholder rights is prohibited:

- The federal or state constitution forbids the taking of bondholder property without just compensation.
- The federal or state constitution forbids state actions that impair contracts.
- The federal or state constitution forbids state actions that are arbitrary and capricious.
- The state, having achieved its public policy goals through the bond issuance, is estopped from modifying the rights previously granted to bondholders.

Whatever the legal theory espoused, the use of administrative securitization will be an issue that is not governed by any existing precedent within the courts of any state in which the concept is proposed. Accordingly, Fitch IBCA fully expects that the authorization of such securitization by a state utility commission will be appealed to the state court of appropriate jurisdiction for a determination that the structure proposed for the transaction is legitimate. If such judicial finding is returned in the affirmative, Fitch IBCA would see no bar to analyzing the deal in the manner outlined within this report to determine whether the transaction, as structured, meets the requirements for an 'AAA' rating. In the unlikely event that an administrative securitization order is unchallenged, Fitch IBCA would investigate the specific state law provisions to determine if all of the necessary elements for a securitization are supported.

nor limit the resulting tariff to a level insufficient to ensure debt repayment. If the regulatory framework does not provide a true-up mechanism, Fitch IBCA will require overcollateralization, subordinated tranches, or other forms of credit enhancement.

Third-Party Energy Providers: In many states, third-party energy providers (i.e. non-utility power generators, energy marketers, and independent brokers) will be granted the right to perform "consolidated billing," i.e. the right to bill customers for all services rendered (including distribution services and transition tariffs) and remit payment back to the utility. If the statute or order allows for third-party consolidated billing, it should also impose minimum credit or collateral requirements on parties wishing to assume this service. Generally, such guidelines will include setting of minimum credit standards; posting of cash collateral to cover the maximum period for which revenues are at risk; and/or requiring that the third party assume personal liability for billed amounts, regardless of collections. For additional information on third-party energy providers, please see Fitch IBCA Research on "California Direct Customer Access Plan," dated Nov. 18, 1997, available on Fitch IBCA's web site at www.fitchibca.com.

Transaction Structure

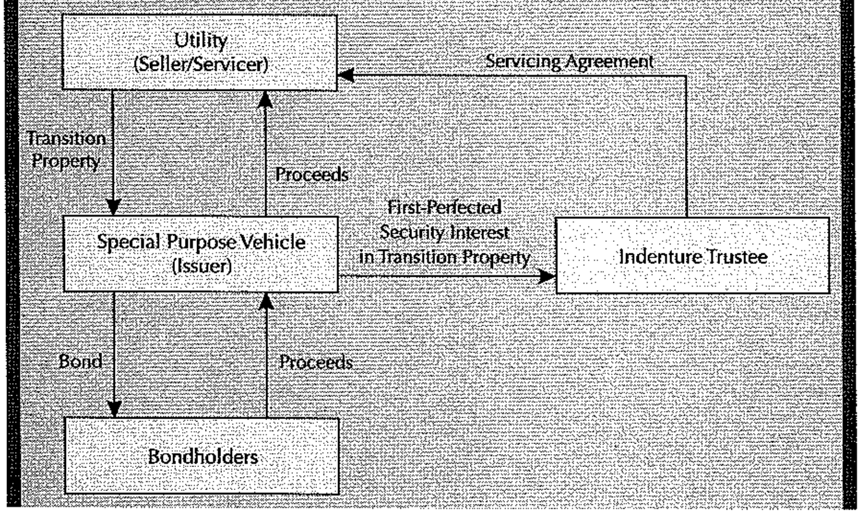
At closing, the utility, as seller, will transfer its ownership interest in the transition property to a bankruptcy-remote SPV (the issuer). To ensure the true sale, all conditions of the enabling statute or regulation must be fulfilled. The SPV, pursuant to its statutory or regulatory authorization, will grant a first-perfected security interest in the transition property to a trustee on behalf of the bondholders. For tax purposes, the transaction will generally be classified as debt of the selling utility and a letter from the Internal Revenue Service confirming this classification may be received prior to issuance. The bonds are generally classified as debt of the utility for accounting purposes as well. The chart at right summarizes the basic structure for these transactions.

The notes issued may be tranched into multiple classes with varying maturities. The principal amortization schedule can be structured as level, mortgage-style, or variable payments. The key to assessing the appropriate amortization schedule is to ensure that proposed payments are consistent with forecasted seasonal fluctuations in collections. While the projected principal amortization schedule will be established at closing, principal shortfalls will generally not trigger a default under the transaction documents. If there is a periodic reset, the true-up mechanism should encompass any prior shortfalls in interest, principal, fees, or any overcollateralization account balances so that principal shortfalls in a given year should be compensated by tariff adjustments in the following period.

Fitch IBCA will evaluate the interrelationship of all aspects of the structure in developing the rating for the bonds. However, certain structural factors will contribute to achieving the highest ratings. For example, the final maturity date for the bonds should fall within the maximum term of the tariff, as defined by statute or order. Back-ended principal payments (i.e. mortgage-style amortization) may strain cash flows in the early periods and increase risk toward the end of the term. Also, given the technology risks associated with the transactions, longer term bonds will be subject to higher cash flow stress scenarios than bonds of shorter duration.

On a qualitative level, Fitch IBCA prefers the tariff to be a relatively small percentage of customers' overall bills and/or that the utility's total rates conform to the regional average. If the transition charge is large or total rates are high, customers may have a greater economic incentive to invest in alternative energy technologies, reduce their consumption, become self-generators, or seek political or legal overturn. This risk is somewhat mitigated in states where total customer rates are capped.

Transaction Structure

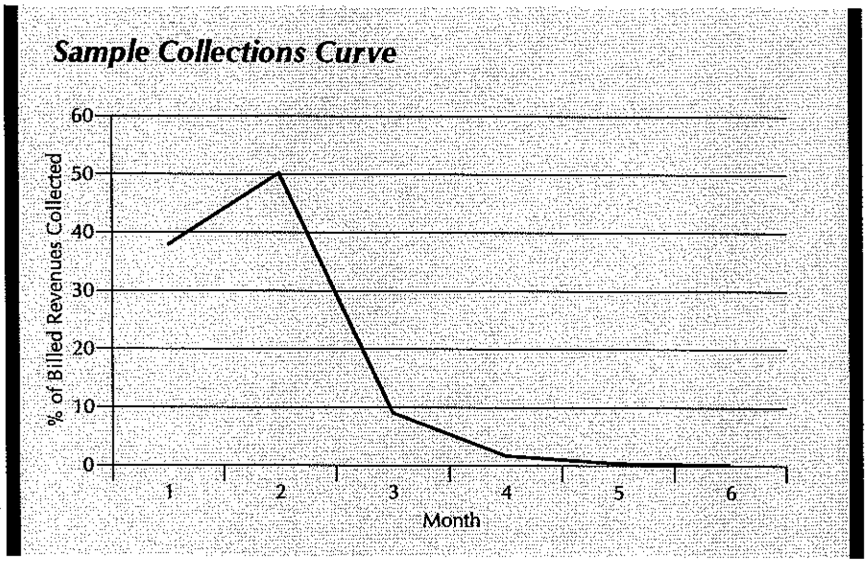


Credit Enhancement: In traditional asset-backed analysis, the level of credit enhancement determines the rating on the securities. However, traditional credit enhancement for debt backed by transition tariffs tends to be relatively small (usually 1%–3% of the initial principal amount). This reduced amount of enhancement is sufficient to achieve 'AAA' ratings for bonds structured with the true-up mechanism since cash flow variability is mitigated by the true-up mechanism and the essential nature of electric service.

When a true-up mechanism adjusts the tariffs at least annually, any cash flow shortfalls will ideally be captured by the end of the following year. Traditional forms of overcollateralization provide some liquidity in the early stages of the deal and greater support toward the end of the transaction. In the later years, the opportunities to true-up, and, thus, the flexibility to recoup principal shortfalls, become fewer. At this point, funded overcollateralization makes up a larger percentage of the outstanding principal balance of the bonds, more closely approaching market enhancement levels for 'AAA' rated bonds in other asset classes.

Sizing of the credit enhancement will depend on the terms of the true-up mechanism, the bond structure, and the strength of the cash flows. Bonds structured with back-ended principal amortization, for example, may require higher credit enhancement in the early years to compensate for lower interest coverage. For bonds structured without a true-up mechanism, higher enhancement levels will be required.

Collection Accounts: An indenture trustee will establish collection accounts into which all tariff collections will be deposited. The frequency of the utility's deposits to the collection accounts will depend on commingling provisions, as described in Utility as Servicer on page 6. Funds held in these accounts will pay expenses, fees, principal, and interest, as well as fund any overcollateralization requirements on a monthly, quarterly, or semiannual basis. Any excess cash collected will normally be held in a reserve account and, if appli-



cable, incorporated into the calculation of the following year's true-up.

Collections Curve: Some bond structures may require the utility to remit cash to the trustee based on a "collections curve," regardless of the actual cash collected. A collections curve specifies the required percentage of each bill that must be remitted to the trust in each of the five or six months after the bill is issued. The curve is calculated based on historical average percentage of bills collected by month after issue, with percentages adjusted annually based on updated collections experience.

Utility as Servicer

The utility will normally act as servicer for the bonds, performing activities such as billing, calculating and collecting the tariff, calculating and filing for true-up adjustments, and sales and usage forecasting. When third-party energy service companies perform consolidated billing, the utility functions as master servicer to consolidate and supervise collection from third parties. Electric utilities will normally have extensive experience in the functions necessary to act as servicer. Furthermore, a utility will frequently have the ability to terminate service due to nonpayment. Thus, even if the utility's credit rating is 'BBB' or lower, it will generally be the optimal servicer for the transaction. Fitch IBCA's due diligence on each utility proposing to act as servicer on a transaction incorporates a review of the utility's forecasting, credit assessment, collections, delinquencies, writeoffs, billing systems, commingling risk, and the availability of alternate servicers, as summarized below.

Forecasting: Since scheduled principal amortization will be based on the utility's sales forecasts, it is important to assess the utility's forecasting ability and accuracy. Utilities generally maintain sophisticated econometric models that relate historical values of energy variables to measures of weather, the economy, and the number of customers. Fitch IBCA reviews the utility's historical sales forecasts and the variances to actual results to determine the peak unfavorable forecast variance, as well as the reasons for such variance, for each customer class included in the securitization. These results are used in the cash flow stress scenarios, as outlined on page 8.

Credit Assessment: Under most state regulatory guidelines, a utility will be required to provide service to all customers regardless of creditworthiness. In some states with dramatic swings in temperature, the utilities may be forbidden from disconnecting service during extremely hot or cold seasons. For these reasons, the key factor in a utility's credit assessment process will be the criteria for requiring additional security from riskier customers. If service cannot be denied, most utilities will require a security deposit for new customers or those who pose a greater credit risk.

Collections, Delinquencies, and Write-offs: The utility should have a well established process for pursuing and collecting delinquencies. However, since customers consider electricity an essential service, historical chargeoff and delinquency rates for utilities tend to be relatively low. It is not unusual for utilities to experience 0.50% average chargeoffs for a 20-year period.

In the deregulated energy services market, an important factor will be the distribution utility's continued ability to disconnect service for nonpayment, even if a third-party energy provider is supplying electricity. In some states, the ability to disconnect may be delayed, especially if a third party is providing consolidated billing.

Billing Systems: Under the current system of "bundled" bills, utility customers receive a bill for one amount incorporating various tariffs, taxes, and surcharges. In the competitive market, most utilities will be required to offer "unbundled" bills, explicitly breaking out bill components. The utility's billing systems must be able to incorporate multiple components of billing information. As part of the due diligence process, Fitch IBCA will review the utility's billing systems to ensure that they are adequately prepared to handle the complexities associated with assessing the transition tariffs and tracking collections.

Commingling: The utility's ability to commingle funds will usually be based on its senior debt rating. Generally, utilities with a short-term rating of 'F2' or above will be permitted to commin-

Servicer Checklist

- ❑ Forecasting methods and accuracy.
- ❑ Procedures for assessing customer credit.
- ❑ Collections process, notice, and disconnection.
- ❑ Historical delinquency and chargeoff data.
- ❑ Billing systems.
- ❑ Commingling of securitized tariffs.
- ❑ Requirements and fees for alternate servicers.

gle funds for 30 days prior to remitting payment to the trust. However, if the utility is a qualified servicer with a short-term rating below 'F2', commingling risk may be mitigated by limiting commingling to a maximum of two days, collecting all receipts through a lock box, or requiring a letter of credit equivalent to 30-day maximum collections.

Alternate Servicers: While a sub-investment-grade utility may be an acceptable servicer based on its operational qualifications, the transaction should provide for the right to replace the utility with an alternate servicer in the event of a decline in credit rating, insolvency, or the failure to perform any of the duties of servicer. The transaction should incorporate a servicer fee sufficient to adequately compensate a backup servicer that takes on this role. It is particularly helpful if the legislature or regulatory order places an obligation on the part of any successor to the utility to invoice and collect on behalf of the bondholders.

Credit Analysis

Since cash flow supporting the bonds will be generated by payments from all or designated categories of customers in the utility's service territory, it is important to analyze the composition of the service territory to determine the size and usage level of the customer base, customer delinquencies, regional economic sensitivities, and weather-related seasonality.

Customer Base: The size and variability of the customer base will have a significant potential impact on the cash flows to the bonds. Fitch IBCA reviews a number of economic factors in its analysis of the customer base, including: the size and shape of the service territory (the geographic footprint); the diversity of the customer pool; the change in housing starts during recessionary periods; exposure to key industries; cyclicality of key industries; historical recessionary bankruptcy data; the municipal rating of any major cities within the service territory; and the existence of any major universities or military bases in the territory.

The residential segment will provide a high level of customer diversification, similar to that found in credit card receivables. Since the tariff will be assessed against a household rather than an individual, it is assumed that the majority of residents moving away from a service territory will be replaced by new residents. Thus, the residential segment will tend to be a large, diversified, and relatively stable source of cash flow.

The utility's commercial and industrial customers could potentially represent significant concentration in the customer base. These customers will tend to be fewer in number and contribute higher tariff revenues per account than those received from residential customers. Industry concentration should also be assessed. Fitch IBCA incorporates the risks associated with customer concentrations into its cash flow stress tests.

Cyclical and Seasonal Patterns: Billed revenues from residential and small commercial customers tend to show minimal sensitivity to economic cycles. In the short term, the greatest historical changes in residential and small commercial usage have been due to weather. Thus, weather patterns often drive the cash flow projections and, consequently, the amortization structure of the bonds. In the long term, the availability of energy-efficient appliances, trends in energy conservation, and the availability of new energy-consuming technologies will likely affect these customers' usage patterns.

Large commercial and industrial customer revenues show greater sensitivity to economic cycles. Such sensitivities should be incorporated into cash flow stress scenarios, as appropriate.

Self-Generation and Alternative Technologies: Because the tariffs will be assessed upon distribution services, the market entrance of alternative energy providers should not affect tariff receipts. However, customers could potentially avoid payment of the transition tariff by performing energy generation on site and disconnecting completely from the distribution grid. The risk that customers will use new and existing technologies to generate power for their own use is referred to as "self-generation."

Given current available technology, Fitch IBCA considers it unlikely that a significant portion of the residential account base will implement self-generation immediately or that alternative technologies will develop sufficiently in the next 10 years to allow for widespread disconnection from the grid. Self-generation in the industrial and large commercial segments, where large energy usage and greater access to capital would make developing a generation system more feasible, is somewhat more likely. Fitch IBCA assumes that the risk of self-generation, driven by the development of new technologies, has the potential to increase substantially beyond a 10-year horizon.

Cash Flow Models and Stress Cases

While the form of cash flow models will vary based on the structure of the bond, statutory and regulatory framework, and amortization schedules, models will address fundamental credit issues common to all securities in this class. These issues include: the forecast customer base (by customer class); tariff levels for each customer class; energy consumption by class; assumptions on collections and chargeoffs; any true-up mechanism and any overcollateralization.

Basis for Methodology: Several factors could potentially reduce the cash flow to the bonds, including economic recessions, loss of large industrial customers, demographic shifts, increased use of self-generated energy sources driven by technological advancements, and errors in forecasting. Fitch IBCA's cash flow stress methodology aggregates these multiple risks and applies a single variance percentage to cash collections. Actual stress cases are described below.

'AAA' Stress Case: Fitch IBCA's 'AAA' stress case stresses four model variables, each of which is meant to incorporate multiple risk factors described above and resulting in a reduction in cash flows below projections.

- Base Error — The first stress variable is applied as a base error to projected revenues. This base error is intended to incorporate the impact of an economic recession, extreme weather changes, changing usage patterns, or general demographic shifts. The base forecast error will equal between 2.0 times (x)–3.0x the historical 20-year peak positive forecast variance. The multiple used and the length of historical data required will vary based on the term of the transaction and the underlying credit risks.
- Self-Generation/Technology Risk — Fitch IBCA assumes that technological uncertainty increases over time, especially for commercial and industrial customers. This would subsequently increase the risk of self-generation as greater technological options become available. To incorporate this risk, Fitch IBCA will assume that the base error increases exponentially over the term of the bonds, based on the perceived risk of self-generation for the utility's customer base.
- Delinquency Rates — To incorporate the effects of delinquency rates on forecast collections, Fitch IBCA will review the utility's historical delinquency experience and apply a multiple of the highest delinquency period. If the transaction uses a collections curve, Fitch IBCA will assume delays in the collection curve.
- Chargeoffs — Despite utilities' historically low chargeoff ratios, Fitch IBCA will apply chargeoff ratios at 5.0x the 20-year historical peak chargeoff. Again, the historical data required may vary based on the credit quality and term of the deal.

Consolidated Billing Default Case: Fitch IBCA will review the credit guidelines established in the financing order for third-party energy providers performing consolidated billing to determine the transactions' maximum exposure to third-party collections. To test the impact of a potential third-party default, the second stress case assumes that third parties take over billing for a large percentage of the customer base and default every year for the entire term of the bonds. The length of the assumed default, and the percentage of the customer base affected, will vary based on the third-party commingling restrictions contained in the statute or order.

Break-the-Bond Case: The third sensitivity strives to test the amount of stress necessary to force an event of default under the bonds. The results of this scenario should be so severe as to be outside what would be considered reasonable for an 'AAA' stress. The exact cases developed to achieve this goal will vary by transaction.

For additional information on this asset class, please refer to Fitch IBCA Research on "California Infrastructure and Economic Development Bank Special Purpose Trust PG&E-1, SCE-1, and SDG&E-1" dated Jan. 12, 1998, Feb. 4, 1998, and March 19, 1998, respectively. All reports are available on Fitch IBCA's web site at www.fitchibca.com.

Credit Analysis Checklist

- ❑ Composition of customer base.
- ❑ Customer concentrations in commercial and industrial segments.
- ❑ Regional industry concentrations.
- ❑ Strength of regional economy.
- ❑ Geographic footprint.
- ❑ Seasonality and cyclicality.
- ❑ Development of alternative energy generation technologies.
- ❑ Disconnection from the power grid by self-generating customers.

STRUCTURED FINANCE **Special Report**

Stranded Utility Costs: Legislation Jolts the ABS Market

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OPINION

To facilitate the transition to a competitive electric market, numerous state legislatures have passed or are considering legislation that, while mandating competition, allows utilities to recover their stranded costs[1] through the imposition of a *competitive transition fee.* To accommodate securitization of revenues from the fees, statutes typically designate as a property right the future revenues from these fees and the utility may sell, assign, or transfer the rights to a financing vehicle. Securities may be issued by a trust or other special purpose vehicle supported by future revenues from these fees.

Only three stranded cost transactions have been completed to date, but this asset class has received considerable attention due to recent passage of stranded cost legislation in California, Pennsylvania, Rhode Island, and proposed legislation in New York. In light of recent legislative developments, Moody's expects total stranded cost securitization volume of $50-$75 billion over the next four years.

Because of the unique characteristics of the highly regulated utility industry and the "asset" that is securitized, the credit analysis of stranded cost securities differs from that of most other assets. For example, underwriting and servicing issues – which are key items of interest in other segments of the ABS market – are less of a concern in a stranded cost context.

Instead, credit analysis of stranded cost securitizations focuses on the legislation that created the fees and on the degree of certainty of future fee generation:

1 See the next section for a more detailed discussion of stranded costs and their origin.

- *Legislative Issues: An understanding of the legislation that created the fees is vital in assessing the credit risk of stranded cost securitizations.* Salient legal concerns include the property characteristics of the fee revenue stream; the transfer and assignability of these rights; security interest issues; and provisions for a true-up mechanism. Importantly, the laws typically state that the sale of the fee revenue by a utility to a financing entity will be treated as a true sale rather than a pledge or other means of financing. Such statutory language simplifies the legal analysis regarding the ownership of the asset, an issue which requires substantial legal analysis in other securitizations.
- *Political Risk: Because investors rely on fees authorized by a legislative act, investors should focus on provisions for rescinding or altering the legislation/rate order that authorizes the tariff.* The irrevocability of the statute is a key consideration because substantial economic downturns for a region may lead to efforts to alter the law/rate order to the detriment of the securitization. The political environment must also be examined because the likelihood of attempts to repeal, alter, or challenge the statute are enhanced if electric utility costs are a contentious political issue.
- *Future Fee Generation: Stranded cost securitizations involve an analysis of many elements found in securitizations of future receivables because the securities are supported by revenue from fees not assessed or billed to the obligors at the date of the securitization closing.* The ability to amortize the securities depends on future fee generation, which is primarily a function of future population in the area serviced by the utility and energy consumption. Factors that influence these items and the resulting cash flow supporting stranded cost securities include: the economic health of the region serviced by the utility; stability and diversification of the customer base; technological advances; and the elasticity of demand for energy. Other credit issues concern the servicing capability of the utility and the accuracy of the utility's population and consumption forecasts.

A stranded cost securitization can achieve a credit rating substantially higher than the rating of the debt of the utility because the viability of the utility is not essential to the assessment and collection of the fee. The statutes mandate that the competitive transition fees are "non-bypassable," meaning they must be paid by all customers regardless of the utility company used as supplier of electricity. Moreover, the fees are required to be collected by the energy distributor or any successor servicing the customer. These features differentiate stranded cost structures from other future receivables transactions.

Table 1
Stranded Investments by Utility Rating, 1996

Utility Rating	Stranded Investments ($ millions)	Percentage
Aa1	33.30	0.02
Aa2	612.18	0.45
Aa3	6,568.56	4.83
A1	4,416.85	3.25
A2	36,639.35	26.96
A3	12,115.44	8.92
Baa1	14,088.35	10.37
Baa2	24,345.18	17.92
Baa3	12,963.99	9.54
Ba1	9,773.19	7.19
Ba2	6,648.01	4.89
Ba3	6,478.26	4.77
NR	1,195.71	0.88
Total	**$135,878.38**	**100.00%**

Source: Moody's Investors Service

WHAT ARE STRANDED COSTS/ASSETS?

To date, a regulatory compact has governed the electric utility industry under which state regulators have provided electric utility providers the exclusive right to service customers in a defined territory. In exchange for this monopoly, utilities have had an obligation to serve all customers, a responsibility that requires substantial investment in plants and generating facilities to meet current and future demand. In this regulatory environment, state utility regulators determined whether investments and expenditures were reasonable before allowing utilities to recover them.

However, the competitive climate for electric utilities is changing. The federal government, the Federal Energy Regulatory Commission, and numerous state legislatures have adopted or are considering policies designed to foster greater competition in electricity markets (see insert "Deregulation in the Electric Utility Industry" on page 3 for a discussion of important utility deregulation legislation). The resulting deregulation of energy markets would allow consumers a choice in selecting among competing electricity suppliers.

Deregulation presents problems for utilities with substantial investments that would have been recovered under a regulatory regime. Competition is expected to depress the market price for power, making some assets uncompetitive. In effect, financial obligations relating to these uncompetitive assets are "stranded" in a competitive marketplace, because the marketplace is not willing to pay high enough charges to cover these obligations when less expensive power is available.

Moody's estimates that stranded costs for U.S. utilities total $136 billion.[2] Stranded costs may originate from several sources, but primarily result from high-cost, state mandated purchased power contracts with independent power producers[3] and costs associated with the investment in generating assets. *Table 1* provides a breakdown of stranded costs by the secured debt rating of the utility.

To provide for recovery of stranded costs in an effort to facilitate utility deregulation, lawmakers in Pennsylvania, Rhode Island, New York, California, and other states have passed or are considering legislation to allow utilities to levy a fee or a tariff, typically called a *non-bypassable* or *competitive transition* fee (or charge). This fee is collected from all customers in the form of a transition charge on existing customers or as a severance fee applied to customers that leave the utility. Cash from these fees, which may be a fixed charge per customer or based on electricity consumption, is intended to be used by the utilities to recover past investment or to buy down above-market contracts with independent power producers. The imposition of the stranded cost charge allows public utilities to implement customer choice with a rate mechanism designed to meet all existing obligations allowed by the legislation or rate order. *Appendix 1* offers a simplified example of how utility rates are set and the impact that stranded cost recovery has on the various rate components in a competitive environment.

To facilitate the securitization of fees by utilities, legislation typically designates the revenue from the fees as a statutory property right and these rights may be sold to a special purpose vehicle or other trust. This entity may issue securities backed by the future cash flow from the fees.

Deregulation in the Electric Utility Industry

The need for large industrial customers of utilities to pay lower electricity rates in an effort to more effectively compete with global rivals is one of the driving forces behind the effort to restructure and deregulate the electric utility industry. The U.S. electric utility industry began to restructure in earnest in 1978 with the passage of the Public Utility Regulatory Policies Act (PURPA).[1] PURPA had numerous goals, including the promotion of energy conservation, the efficient use of electric utility resources, and the development of independent power projects defined as "qualifying facilities." This set the stage for more choice for the electric customer.

The most significant change in structure and deregulation is contained in the National Energy Policy Act of 1992 (NEPA). Prior to NEPA, utilities used their transmission systems to serve their customers and to conduct wholesale power transactions primarily with adjacent or regionally based utilities at prices as negotiated between the parties. However, the enactment of NEPA mandates open access to transmission for wholesale generators at prices comparable to what the transmission owner would charge itself, and charges the Federal Energy Regulatory Commission (FERC) with the responsibility of developing a methodology for pricing transmission services and expanding transmission facilities where necessary. Under NEPA, wholesale electricity will be sold essentially as a commodity through a transmission system that is available to all on a comparable basis.

FERC's landmark Order 888, issued in April 1996, fulfills the directive of NEPA and culminates the move toward an open wholesale market begun by PURPA. The order addresses the two issues, pricing and access, that are key to the establishment of an open market for electric power. Furthermore, the order plays a large role in the development of a competitive retail energy market by providing a framework to resolve technical, ownership and operational issues.

1 For more information on utility legislation see Moody's Industry Outlook, October 1993 and October 1996, "The Metamorphosis of PUHCA, PURPA, and Comprehensive Utility Reform," September 1996, "Stranded Costs Will Threaten Credit Quality of U.S. Electrics," August 1995, and "Regulatory Assets Pose Risks to U.S. Electric Utilities as the Industry Faces Heightening Competition," December 1994.

2 See "Moody's Calculates Little Change in Potential Stranded Cost Investments: Regulation Will Provide Recovery for Some, But Not All, Companies," *Moody's Structured Finance*, January 24, 1997.

3 As an example of high cost contracts as a stranded cost, the three investor owned California utilities were mandated in the early 1980s by the California Public Utilities Commission to enter into long-term contracts with independent energy producers. The contracts contained fixed payments to the producers based on a forecast that the price of gas would increase from 4-5 cents per kilowatt hour to 12-13 cents. This forecast did not materialize and, as a result, the contracts are now vastly overpriced. These contracts start to expire in 1997 and 1998.

The Impact of Stranded Cost Securitization on Utilities

Recent legislation that gives rise to the securitization of potential stranded costs is generally positive for investor owned utilities in that it provides for the recovery of stranded costs through rates. However, holders of utility debt (referred to as bondholders) should be aware that their position could be compromised if the issuer uses the proceeds of the securitization in such a way as to increase the pool of investors entitled to its cash flow.

The proceeds from the securitization of stranded costs will allow investor owned utilities to pay down immediately some of their stranded costs associated with assets that will not be competitive in an open marketplace. While the securitization will not be an obligation of the company, cash flow associated with the stranded cost recovery portion of the customers' electric bills will service the securitized debt. The stranded cost recovery "charge" will not increase electric rates for the consumer. Stranded costs are being recovered in current rates since virtually all costs are included in most investor owned utilities' rate bases. In the future, current rates will simply be described differently. A portion of the rate a customer pays will be for electricity and service, and a portion will be designated a stranded cost recovery charge.

The prevailing opinion of issuers as to how proceeds of the securitizations will be used is that current bondholders and stockholders will be paid out in such a way as to maintain capital structure ratios, but with a smaller balance sheet. However, investors should be mindful of the fact that although the pool of company bondholders will shrink, the introduction of securitized bondholders entitled to the same cash flow to which current bondholders are entitled may compromise current bondholders' positions. In a bankruptcy situation, the holders of the securitized bonds may actually be in a superior position, since the bonds will be issued through a bankruptcy remote vehicle, making continued collection of debt service after the bankruptcy of an investor owned utility entirely likely. In order for remaining bondholders in investor owned utilities to maintain their current position, enough bonds must be redeemed such that the securitized bondholders do not require a greater portion of the cash flow than did the previous bondholders.

The illustration below demonstrates the potential difficulties for bondholders. This example assumes that a securitized bond offering costs 200 basis points less than the debt of the company. In addition, the company chooses to use the proceeds of the securitization to pay down debt and buy back equity in equal amounts. In this example, total cash payments of $19.2 are 4% less. However, bondholder and securitization interest payment requirements are higher after securitization ($8.4), than before ($8), by virtue of the fact that the company is replacing equity with debt. Actual company results will vary widely.

Investors	$Amount	Cost of Capital	Cash Payments	% Cash Payments
Current				
Bondholders	100	8%	8	40
Equity	100	12%	12	60
Total	**$200**		**20**	**100**
Post Securitization				
IOU Bondholders	90	8%	7.2	37.5%
Securitized Bondholders	20	6%	1.2	6.25
Equity	90	12%	10.8	56.25
Total	**$200**		**$19.2**	**100.0**

PROSPECTS FOR SECURITIZATION OF STRANDED COSTS

Three securitizations of stranded cost fees have been completed to date (see *Appendix 2* for more detail on these transactions):

- Puget Power Conservation Grantor Trust 1995-1[4]
- Nuclear Moratorium Asset Securitization Fund
- Orchid Securities Ltd

A tariff designed to recoup Puget Power's expenditures relating to its energy conservation program was securitized in the $202.25 million Puget Power transaction, completed in June 1995.[5] The securitized asset in the June 1996 Nuclear Moratorium Asset transaction was revenue from a 3.54% fee imposed on utility customers in Spain to finance the costs of closing three nuclear power plants in 1984. The 25-year deal was supported by a guarantee from the Spanish government. Fees used to defray costs from the closure of Italian nuclear power plants were securitized in Orchid Securities, a $355 million deal that closed in May 1996.

Although only three transactions have been completed to date, securitization prospects have been enhanced due to recent legislative activity, most notably:

4 The Puget Power transaction was technically not a stranded cost securitization, but rather a securitization of cash flow from conservation assets.
5 See "Puget Power Conservation Grantor Trust 1995-1," *Moody's Structured Finance*, December 15, 1995.

- California legislation (AB 1890) adopted in September 1996 provides a framework for the state's investor-owned utilities to issue debt securities backed by revenues received from *competitive transition charges* that are authorized by the California Public Utilities Commission (CPUC).
- Pennsylvania legislation (HB 1509) passed in December 1996 is similar to California's AB1890, except that a concurrent rate reduction is not a condition for implementation of a tariff. The bill anticipates securitization of the fee revenue, including a utility commission's right to issue an irrevocable order, a pledge by the Commonwealth of Pennsylvania not to alter or reduce the value of the transition charge (except if adequate compensation is paid), and a true-up mechanism. The maximum term of any securities issued pursuant to this legislation is 10 years.
- Proposed New York State legislation (The Electric Ratepayers Relief Act of 1996) is similar to the California legislation. This act would create *qualified rate orders* to be issued at the discretion of the New York Public Service Commission. All or a portion of utilities' qualified intangibles expenditures would be recovered through the application of user fees.
- Rhode Island has passed legislation allowing recovery of stranded costs.
- More than 40 states are considering electric utility deregulation, providing further impetus for additional securitizations of stranded costs.

EVALUATING THE RISKS OF SECURITIES BACKED BY STRANDED COSTS

Because of the unique characteristics of the highly regulated utility industry and the "asset" that is securitized, the credit analysis of stranded cost securities differs from that of commodity assets such as credit cards and auto loans. For example, underwriting and servicing issues, which are key items of interest in other segments of the ABS market, are less of a concern in a stranded cost context. Instead, *key credit concerns revolve around the legislation that created the fees and the prospects for collecting future revenues from the fees.* This section discusses the various issues affecting the credit risks in these securities, starting with legal and structural concerns, irrevocability of the legislation/rate order, followed by future fee generation analysis.

Legal and Structural Considerations

The legal and structural risks in a stranded cost securitization are similar to those found in other securitizations; however, because legislation that authorizes the fee revenue anticipates securitization, fewer ambiguities exist regarding ownership of the asset.

In a stranded cost securitization, the asset is the irrevocable property right to collect cash flow from a tariff or fee on utility customers imposed by a utility with the approval of appropriate regulatory authorities. Legislation typically allows the utility to sell, assign, or transfer the property right to a financing vehicle. Furthermore, legislation sets forth specific requirements that, if satisfied, will accomplish a "true sale."

These requirements eliminate a source of legal uncertainty encountered in many asset-backed transactions. A significant legal issue in securitizations is whether the assets supporting securities have actually been sold by the seller. If not, the assets will be part of the bankruptcy estate of the originator and any payments with respect to them could be delayed due to the automatic stay provisions of the Bankruptcy Code. To avoid this risk, many transactions are structured as a true sale. In other securitizations, true sale analysis involves a review of the facts and circumstances of the transaction, and conclusions are based on analyses drawn from case law. The fact that stranded cost legislation specifies the requirements for a true sale simplifies the legal analysis regarding this issue.

However, certain legal risks are particular to stranded cost securitizations. These risks primarily relate to the authorizing statute and how the rate order is accomplished. A primary concern for holders of these securities is alterations in the legislation/rate order that authorized the stranded cost fee revenue – an issue discussed in the next section. Items of concern include the following:

- Regulatory process
- Definition of fees as a property right
- Assignment and true sale issues

- Bankruptcy remoteness of issuer
- Provisions for a true-up mechanism
- Indenture issues
- Transaction structure

Regulatory Process

Typically, a utility applies to a regulatory agency for permission to issue securities backed by fee revenue to recover costs (called a *rate order*) that it believes are stranded.[6] The application usually contains detailed information on (1) the utility's stranded costs, (2) the utility's proposal for the sale of the fees and the issuance of securities, (3) the benefits to consumers, and (4) its planned use of the proceeds. Within a specified time after the application, the utility commission issues a final rate order for all or a portion of the amount of stranded costs the utility may recover that, in the commission's opinion, are just, reasonable, and in the public interest. The rate order may require that the proceeds from the sale of the securities be used to reduce debt and equity associated with the utility's stranded costs.

In California, a utility that seeks compensation for the recovery of stranded costs would apply to the CPUC for a financing order that would designate these costs as *fixed transition amounts.* A decision on the utility's rate order must be rendered within 120 days of the utility's application.

Is the Right to Cash from the Fees Defined as a Property Right?

Investors should determine if the legislation designates as a property right the right to the cash flow from the fees. This is an important factor because if legislation defines the fees as a property right, the cash flow from the fees can be sold by the utility to a special purpose vehicle for purposes of a securitization; provisions for security interests in the property can also be developed.

For example, California legislation defines the fees as *transition property*. Transition property is the property right created by the legislation including " ... without limitation, the right, title, and interest of an electrical corporation or a financing entity to all revenues, collections, claims, payments, money, or proceeds of or arising from or constituting fixed transition amounts that are the subject of a financing order ... that are authorized by the commission ..." Similar language is used in the New York proposed legislation and the Pennsylvania statute, where the property right is in *special intangibles property* and *intangible transition property*, respectively.

Assignment and True Sale Issues

Legislation typically provides that revenues from the fees may be sold. For example, the Pennsylvania law states that the " ... interest of an electric utility in intangible transition property may be assigned, sold, or transferred to an assignee and may be pledged or assigned as security by an electric utility or assignee to or for the benefit of a financing party."

Furthermore, the laws typically state that the sale of the transition property by a utility to a financing entity will be treated as a true sale rather than a pledge or other means of financing. Language on this issue is typically explicit. For example, California legislation provides that a transfer of transition property by a utility to a financing entity " ... shall be treated as an absolute transfer of all of the transferor's right, title, and interest (as in a true sale), and not as a pledge or other financing ..." Such statutory language simplifies the legal analysis regarding the ownership of the asset, an issue which requires substantial legal analysis in other securitizations.

Furthermore, the legislation to date has addressed the means by which a security interest in the fee revenue is perfected. In some legislation, a valid and enforceable security interest in fee revenue is perfected by filing with the appropriate utility commission.

Bankruptcy Remoteness of Issuer

Under the California structure, a utility would simultaneously apply to the CPUC for a financing order and to the Infrastructure and Economic Development (IED) Bank to authorize the issuance of

6 The definition of recoverable stranded cost varies by state and is ultimately determined by the appropriate regulatory commission. Under the recently passed California law, *transition costs* are defined as costs for generation-related assets and obligations that were being collected in commission-approved rates on December 20, 1995, that may become uneconomic as a result of a competitive generation market. Also included are costs incurred after December 20, 1995, for capital additions to existing generating facilities that the commission believes are reasonable and should be recovered, provided that the costs are necessary to maintain the facilities through December 31, 2001. Under pending New York legislation, *qualified intangibles expenditures* are defined as expenditures of a utility which did not result in the acquisition of real or tangible personal property. Also included are amounts to refinance or retire debt or equity and certain costs. The Pennsylvania legislation defines *qualified transition expenses* as stranded costs of a utility that are approved by the commission for recovery.

securities backed by fee revenue. If the application is approved, the IED Bank may authorize a *financing entity*, which could be itself or another designated entity, to issue *rate reduction bonds*. Under Pennsylvania and proposed New York legislation, any entity may issue securities backed by fee revenue.

Evaluating the bankruptcy remoteness of the issuer is a consideration in all ABS transactions.[7] In a stranded asset context, if a state agency is the issuer of securities, the existing debt of the agency, restrictions on future debt issuance, and the linkage to the state must be analyzed.

True-up Mechanism

Most statutes call for a *true-up mechanism*, in which the fee levied on customers is adjusted at regular intervals based on the projected amortization of the securities. The true-up mechanism is an important consideration in assessing the certainty of payments to investors and can be thought of as a correction mechanism if cash flow from the assets does not meet expectations. Understanding the correction mechanism is crucial to analyzing the credit risk of stranded cost securitizations.

Puget Power Conservation Grantor Trust employed a true-up mechanism in their securitization of revenue from a per customer fee. Prior to deal closing, Puget Power forecast its customer base (both number of customers and type of customer), delinquencies, and chargeoffs for the next 10 years. The tariff schedule was then set at levels, which, in view of Puget Power's forecast, would amortize the securities in accordance with the projected security amortization schedule. Every September, the trust's actual asset balance is compared with the projected asset balance. If there is more than a 2% variance (above or below), Puget Power will re-forecast its 10-year projections and apply to the utility commission for a new tariff schedule sufficient to amortize the securities to return to the projected amortization schedule by the following September.

Indenture Issues

The utility's indenture is examined to determine whether revenue from the fees could be considered the property of first mortgage bond holders. The underlying noncompetitive assets, excluding purchased power contracts with independent power producers, most likely have been pledged to secure the issuance of first mortgage bonds, the traditional utility financing method. It is uncertain whether the fee revenue stream would be subject to the first mortgage bond indenture lien since many were written in the 1920s and 1930s when stranded asset securitization was not contemplated.

Transaction Structure

Structural issues for securities backed by other assets, such as auto loans and credit cards are common to stranded cost securitizations.[8] Important considerations include:

- Credit support: Protection mechanisms available to investors to absorb losses
- Structural considerations: How cash flows are allocated

Numerous forms of credit support are available to absorb losses, including subordination, overcollateralization, reserve accounts, and financial guarantees. It should be noted that securities are generally not direct or indirect obligations of any state.

Credit support for previous stranded cost transactions has been low compared to credit support for other asset types. For example, for certificates issued in the Puget Power transaction, rated **Aa2**, credit support (in the form of overcollateralization) relative to the original certificate balance was 0.12%. The low support is due to the projected stability of fee revenue and the presence of a true-up mechanism, which would adjust fees to retire outstanding securities.

Securities may be issued from a grantor trust, owner trust, or other special purpose vehicle. Grantor trusts are pass-through entities which can support single or senior/subordinated class structures. Each holder of a certificate is treated as an owner of the underlying assets. Thus, principal and interest allocations are proportional to the respective interests of each class in the collateral. Although subordinate class principal and interest may be used to pay credit losses for the senior

7 See "Credit Analysis of Structured Securities," *Moody's Structured Finance*.
8 For more detail on generic securitization structural issues see "Moody's Approach to Rating Automobile-Backed Securitizations: The Driving Force," *Moody's Structured Finance*, August 11, 1995.

class, principal allowances allocable to the subordinate class cannot be used to accelerate repayment of the senior certificate classes. In an owner trust or other special purpose vehicle, "fast pay" or turbo structures are permitted in which the allocation of principal from the entire pool is paid to designated tranche(s), until paid in full.

One class of certificates was issued from a grantor trust in the Puget Power transaction. Future stranded cost structures are anticipated to have multiple classes issued from an owner trust structure or other special purpose vehicle, which allows more creativity in distributing cash flows to various tranches.

Irrevocability: A Regulatory and Political Issue

Because investors rely on fees authorized by a legislative act, investors should focus on provisions for rescinding or altering the legislation or rate order that authorizes the tariff. Under California law, financing orders and fees are irrevocable; the commission may not alter, amend, revalue, or in any way reduce or impair the value of the transition property. Under Pennsylvania and proposed New York law, the appropriate commission may specify that all or a part of a qualified rate order is irrevocable.

Even if the legislation and/or rate order is irrevocable, investors must consider the history of the legislation and/or rate order, the type of support it receives from the various parties involved in the rate making process, and the type of opposition it faces, if any. This analysis sheds light on the likelihood the legislation and/or rate order could subsequently be undermined. If the bill has broad political and consumer advocate support and there are perceived economic benefits to rate payers, the probability that the bill can withstand challenges is enhanced. For example, the California legislation provides for a 10% reduction of rates concurrent with the implementation of stranded cost recovery. Proposed New York legislation specifies that any order must provide significant rate savings.

The likelihood of attempts to repeal, alter, or challenge the statute are enhanced if electric utility costs are a political issue and constituents view the various legislative and rate orders of the non-bypassable fee as a bailout. Some state courts have played an active role in the rate making process, overturning orders deemed to be inconsistent with state statutes. This role must be examined, since it can affect the revenue from the fees.

The size of the surcharge relative to a customer's overall bill is a consideration. Low fees are not likely to be noticed by consumers. If cash flow necessary to pay off the securities does not materialize, the resulting increase in the fees due to the true-up mechanism would likely not be noticed by consumers. On the other hand, a high tariff would leave little room for future increases and such increases may lead to political action.

To investigate the magnitude of the tariff necessary to amortize securities, Moody's has developed cash flow models to evaluate the security cash flows under stressed scenarios. Variables that are incorporated in modeling the cash flow from the fees include the number of customers, consumption according to customer type, elasticity of demand for electricity, and delays in payments due to delinquencies and charge-offs. From fee revenue cash flows, a bond cash flow model is developed, which sheds light on the tariff necessary to amortize the securities in a timely manner.[9] This analysis provides insight on the tariff necessary in a stressed environment, and further judgment can be used to determine whether the size of the tariff is politically palatable.

Evaluating Future Fee Generation and Collections

In traditional securitizations, securities are supported by assets such as loans or leases, which are borrower obligations to make future cash payments to amortize the loan or lease. In contrast, for a stranded cost transaction, the securitized asset is future revenue from fees paid from the utility customer base or from customers that switch energy providers. The obligation to pay the fee for a

9 A consideration in the security cash flow model is the priority of payment to the utility and the securitization bondholders. For example, assume that a customer's monthly bill is $100 and the tariff is $10. If the customer remits $50, the securitization could receive the full $10 or a pro-rata share, in this case $5.

particular party is conditional on residence in a particular utility jurisdiction and, if the fee is based on energy usage, consumption of electricity. Because stranded cost securities rely on future payments which are not, at the closing of the securitization, obligations of any party, these securities have some characteristics that are similar to future receivables securities.

Future receivables refers to receivables that do not exist today but which may exist in the future.[10] Future receivables securities, which have become popular recently, particularly in emerging markets, can achieve a rating higher than the rating of the debt of the originator of the future receivables if certain conditions are met:

- The product or service that generates the receivables is essential and not easily replaced.
- The business or industry in which the receivables are generated is consistent and stable over sustained periods of time. Furthermore, the receivables would continue to be generated if the originating entity becomes subject to a bankruptcy proceeding due to the importance of the product or service.

These conditions are easily met in an electric utility context. Electricity is a necessity and, with current technology, not easily replaced. Most electric utility companies have rated debt and have been in existence for many years with documented stability in the generation of electric power. Moreover, electricity would still be generated and consumed in the event of severe financial distress of the utility. *Because electricity is an essential service, and even utilities in stressed financial situations have continued to produce energy consistently, securities backed by stranded costs can achieve a high level of credit quality, even substantially higher than the rating of the originating utility.*

Another feature that makes stranded cost securitizations stronger than other future receivables transactions is that the revenue from the fees is not dependent on the existence of the originating utility. Legislation typically requires that any successor to the original utility (due to bankruptcy, reorganization, merger, or acquisition) must satisfy all obligations of the original utility, including the collection of fee revenue for the securitization.

Considerations in Projecting Future Fee Revenue

If the tariff is a fixed charge per customer as in the Puget Power transaction, the cash flow supporting a stranded cost securitization is primarily determined by the future number of customers in a utility area. Other cash flow considerations include the utility's collections ability and the relative mix of residential, commercial, and industrial customers. The latter consideration is important to a utility because large commercial and industrial customers typically consume more energy and therefore cover a larger percentage of the utility's fixed generating costs. To illustrate a positive credit scenario, higher than projected population in a utility area would lead to a greater customer base and resulting higher than expected fee cash flows. If the actual security balance is less than originally expected, the true-up mechanism may be triggered, leading to a lower tariff. On the other hand, lower than expected population as a result of demographic changes or regional economic weakness may lead to a higher tariff to amortize the stranded cost securities by their final maturity.

If the fee is based on energy consumption, the revenue from the fees is a function of the number and type of utility customers along with the energy use per customer. Thus, key variables in the credit analysis of stranded cost securitizations are the projected population and possibly, energy consumption. Factors that influence these items and the resulting cash flow (and variability) supporting stranded cost securities include:

- Economic health of the region
- Stability and diversification of customer base
- Technological advances

10 For more detail on future receivables securities see "Innovations in Structured Finance: Future Receivables," *Moody's Structured Finance,* July 28, 1995.

- Elasticity of demand for energy

Other considerations that influence the credit quality of these securities include:

- Evaluation of utility's historical projections
- Underwriting/servicing

Economic Health of the Region

The projected economic health of an area served by the utility is a key component in the analysis of the credit quality of stranded cost transactions because the economic climate influences population and aggregate spending (including electricity consumption). For broad customer areas, projecting economic activity is essentially a macroeconomic endeavor; systematic factors such as the region's aggregate economic growth, employment, tax climate, and political considerations are key variables.

For utility jurisdictions covering a narrower customer base, unique or nonsystematic factors are more of an issue. A smaller area may have a narrower business base and may rely on a few industries to drive economic growth. An area that relies on multiple industries for economic growth will likely have a more stable business climate than an area that is dependent on the fortunes of one industry. In the latter case, the area's prospects will falter if that industry runs into hard times; examples include areas that rely exclusively on government defense spending or oil production.

Stability and Diversification of Customer Base

Also considered is the residential/commercial/industrial mix. A utility jurisdiction with a large residential base relative to the commercial base will likely experience lower volatility in energy consumption. This is due to the fact that consumption by commercial/industrial operations is more closely tied to the business cycle. Residential customers usually pay electric bills before other debt to avoid any non-payment-related service interruption. Furthermore, residential customers are less likely to quickly embrace new energy production technologies.

The residential base will also be more diversified with no obligor concentrations; in contrast, energy consumption by a few major companies comprises a significant percentage of revenue for some utilities. Utilities with substantial concentrations resulting from major commercial/industrial customers are vulnerable if these entities falter or leave the area.

Technological Advances

Energy consumption per customer is a consideration if the tariff is based on energy usage. Historical data can identify trends in energy consumption and can be used to project energy utilization. Although energy consumption is reasonably predictable in the short term, the possibility of technological advances in energy production that would lead to a reduction in energy consumption makes long-term energy consumption projections difficult and highly variable.

Elasticity of Demand for Energy

The elasticity of demand for energy must be considered for various types of customers for securitizations supported by revenues from fees based on energy usage. The elasticity of demand for energy measures the sensitivity of energy consumption relative to a change in price. Elasticity of demand varies by type of customer, with residential customers the least responsive to price changes. Large commercial/industrial customers are more sensitive to price changes as they have greater energy alternatives and are more likely to embrace new energy technologies.

Consumer reactions to a substantial increase in the tariff from the true-up mechanism must be understood. If a tariff increase from the true-up mechanism is substantial, large commercial/industrial customers would likely seek pricing concessions or energy alternatives, leading to a reduction in revenue if the fee is based on consumption. Companies fleeing the area serviced by the utility is another, more drastic, response to higher fees. On the other hand, residential customers would probably not reduce energy usage substantially in response to a tariff increase because of their inelastic demand; instead, clamor for political action to undermine the legislation/rate order would pose the greatest risk for investors in stranded cost securities.

Evaluation of Utility's Historical Projections

Stranded cost securitizations generally call for regular adjustments in the fee in order to amortize the securities by their legal final maturity. Because the tariff is based on predictions of customer base and, possibly electricity usage, the forecasting ability of the utility must be evaluated. Most utilities employ economists and statisticians and, because these forecasts are used extensively in the regulatory rate-setting process, can provide substantial historical information on actual and projected energy use for the customer base. Econometric models using historical data such as previous consumption and regional employment and production combined with qualitative adjustments are the basis for these forecasts.

Low historical forecasting errors provide comfort that subsequent tariff adjustments will likely be modest and hence, the likelihood of shortfalls to investors is small. On the other hand, large forecasting errors and substantial shifts in key variables make the credit performance of the securities more variable.

Underwriting/Servicing

The underwriting and servicing standards of the servicer are key considerations in many transactions backed by consumer obligations such as subprime auto and credit card receivables transactions. However, these items are less of a concern for stranded cost transactions for the following reasons:

- Very little underwriting activity exists as utilities must provide service to all prospective customers;
- The procedures for handling of delinquent accounts are determined by utility commissions. In fact, low income households may be subsidized;
- Few remedies exist for utilities in the case of customer nonpayment of obligations. Although repossession of delinquent vehicles is common for subprime auto lenders, turning off a customer's electricity is generally not a utility's first alternative due to possible political repercussions.

Key considerations regarding servicing include how these standards and the resulting payment performance may change in a competitive environment and whether the utility has the systems capabilities to segregate funds and produce servicing reports for a securitization.

SUMMARY

Credit analysis of stranded cost securitizations focuses on the legislation that created the tariff and the prospects for future revenue from the fee. Because legislation anticipates securitization, fewer ambiguities exist regarding ownership of the revenue stream from the fee. Instead, the primary legal issue is the irrevocability of the law/rate order that created the tariff. Regarding future fee generation, the size of the customer base and projected energy use are key variables.

A stranded cost securitization can achieve a credit rating substantially higher than the rating of the senior debt of the utility because the viability of the utility is not essential to the assessment and collection of the fee and the fee revenue can be isolated from the property of the utility. The statutes mandate that the competitive transition charges are "non-bypassable," meaning they must be paid by all customers regardless of the utility company used as supplier of electricity. Moreover, the fees are required to be collected by the energy distributor or any successor servicing the customer.

APPENDIX 1

Utility Rate Determination: An Example

The following is a simplified example of how rates are set and the impact that a stranded cost recovery framework has on the various rate making components in a competitive environment.

Rates are set by the state's public service commission to enable a utility to earn a "reasonable" rate of return on its investment. The variables used in calculating rates are:

- Rate base or net plant
- Return on investment-based on weighted average cost of capital
- Expense items such as depreciation, fuel costs, and taxes

In *Example 1*, the utility has a plant investment of $1,000,000, financed by the issuance of long-term debt (50%), preferred stock (5%), and common equity (45%) in the amounts set forth below. The securities have an implicit cost ranging between 8%-14%, with equity having the highest cost.

The primary utility asset, which is net plant, is the sole component in determining the rate base (i.e. $1,000,000). Rates are established by applying a rate of return (10.85%) on the company's rate base. The rate of return is calculated by computing the weighted average cost of capital[11] multiplied by the rate base to determine the required amount of operating income ($109,000). This is the amount of revenue needed to pay interest on debt, pay preferred dividends, and earn a return on common equity that compensates shareholders. The utility pays federal, state, and local taxes ($100,000); fuel costs ($82,000); and depreciation ($50,000). These items are usually expensed on a dollar-for-dollar basis and are added to operating income to obtain the total revenue requirement ($341,000). No increase in utility rates is necessary because the total revenue requirement ($341,000) is equal to the existing revenues ($341,000).

11 The weighted average cost of capital is obtained by dividing total debt ($500,000), preferred stock ($50,000), and common equity ($450,000) by total capitalization (the sum of debt, preferred stock, and common equity = $1,000,000) times the weighted cost of interest on debt (8%) and return on preferred (11%) and common (14%) stock.

Example 1

Assets ($000)

Net Plant $1,000

Liabilities/Equities ($000)

	($000)	Capital Structure (%)	Cost of Capital (%)	Weighted Average Cost of Capital (%)
Debt	500	50	8.0	4.00
Preferred	50	5	11.0	0.55
Common Equity	450	45	14.0	6.30
Total	**1,000**	**100**		**10.85**

Rate Base = $1,000

Income Statement ($000)

Operating Income = ROR on rate base (net plant x weighted average cost of capital) =	$109
Taxes	100
Depreciation	50
Fuel Costs	82
Total Revenues Needed =	**$341**
Existing Revenues	341
Revenue Increase	0

Example 2

Assets ($000)

Net Plant	$700
Stranded Costs	300
Total Assets	**1,000**

Liabilities/Equities ($000)

	($000)	Capital Structure (%)	Cost of Capital (%)	Weighted Average Cost of Capital (%)
Debt	350	50	7.50	3.75
Preferred	35	5	10.50	0.53
Common Equity	315	45	14.00	6.30
Total	**700**	**100**		**10.58**

ABS securitization $300

Rate Base = $700

Income Statement ($000)

Operating Income = ROR on rate base (net plant x weighted average cost of capital) =	$74
Stranded surcharge[1]	32
Taxes	98
Depreciation	48
Fuel Costs	82
	$334
Total Revenues Needed =	**$334**
Existing Revenues	341
Revenue Increase	(7)

1 Stranded surcharge on $300 plus interest at 6% or $2 per annum; ABS is amortized in approximately 10 years or $32 per annum.

The situation depicted in *Example 2* is the same as in *Example 1*, except that the noncompetitive stranded costs ($300,000) that remain with the utility will be removed from rate base because the utility is allowed to charge a separate surcharge to repay the ABS securitization. The relative percentages of the capital structure are assumed to remain unchanged in this example because the proceeds from stranded securitization are used to retire debt, preferred stock, and equity in proportion to the original structure. Rate reduction of $7 is possible if higher coupon capital is retired, lowering the embedded rate of return. Also, the ABS securitization will be financed at a lower cost of capital since no equity return is essential. The effective tax rate should remain unchanged and depreciation should decline slightly since a portion of the noncompetitive plant may not be operated. Overall, rates are reduced 2.1% because of the stranded cost framework.

APPENDIX 2

Summary of Stranded Cost Securitizations

Puget Power Conservation Grantor Trust 1995-1

The securitized asset in the Puget Sound Power & Light transaction consisted of revenues from conservation investments. Conservation assets are unamortized expenditures to subsidize customers in a variety of energy conservation measures such as energy-efficient light fixtures and insulation. In 1992, these conservation assets consisted of 7% of Puget's assets; with a competitive environment approaching, Puget could not rely on a rate-based recovery of these assets.

As a response to this potential stranded cost, the Washington State Legislature created a statutory right to recovery of conservation assets in June 1994. Under this law, the mechanism by which Puget Power recovers the expenditures is a tariff charged to each customer (residential, commercial, industrial, outdoor) in their utility bill. The origin of the tariff is the State of Washington Conservation Financing Statute, which, among other items, (1) grants Puget Power (as well as other utilities in the state) the right to include in their rate base the amount of Puget's conservation expenditures plus the certificate rate, trustee fee, and servicing fee, (2) expressly defines this statutory right to recover conservation expenditures as property that may be sold, pledged or otherwise made the basis for the issuance of securities, and (3) obligates the Washington Utilities and Transportation Commission to maintain rates under the tariff sufficient to fully amortize the conservation assets and pay the certificate rate, trustee fee, and servicing fee.

In June 1995, Puget completed its first securitization under this statute. $202.25 million of securities were issued from Puget Power Conservation Grantor Trust 1995-1. Credit enhancement consisted of overcollateralization of $244,850. Prior to the closing of the transaction, Puget Power forecast, for the next 10 years, its customer base (the number of customers and type of customer), delinquencies, and chargeoffs. The tariff schedule was set at levels, which, in view of Puget's forecast, will amortize the aggregate amount of the conservation assets in accordance with the projected amortization schedule.

Every September, the trust's actual asset balance will be compared with the projected balance. If there is a 2% variance (above or below), Puget Power will re-forecast their 10-year projections and apply to the Utility Commission for a new tariff schedule sufficient to amortize the assets to return to the projected amortization schedule by the following September.

On March 31, 2004, a final variance will be taken and the tariff adjustment will be applied for, if necessary. From then until the final maturity of the certificates, there will be no tariff adjustment mechanism and the transaction will pay out from collected cash flow.

The utility commission cannot reject a tariff adjustment and has 30 days to approve it. Should the commission delay more than 30 days, the expected maturity of the deal will be extended by the number of days that the commission delays. Should the commission delay more than 11 months, the new tariff automatically goes into effect.

Nuclear Moratorium Asset Securitization Fund

The Spanish Government's National Energy Plan of 1983 recommended the full and unconditional construction termination of five nuclear power plants in Spain. In 1994, legislation was passed that established the full and unconditional stoppage of the three nuclear power plants under construction. The law also recognized the compensation rights for each nuclear project. To compensate the utility companies for $5.7 billion of debt financing to fund the projects, the Spanish Government imposed a 3.54% tariff based on the billing of electricity to final customers.

Securities issued in the Nuclear Moratorium Asset Securitisation Fund, which closed in June 1996, are backed by this 3.54% fee. The senior securities issued in the transaction were rated **Aaa** on the basis of three guarantees issued by the Spanish Government, an unlimited line of credit provided by a GIC provider (an agency of the Spanish Government), and the cash flow structure in which overcollateralization is created as the senior bonds are paid down. Interest on the securities is paid quarterly based on LIBOR. The 25-year term on the securities is substantially greater than the Puget Power securities.

Stranded Utility Costs Securitization: An Energized Market

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OPINION

Utility stranded costs ratings consider the legal and structural factors that isolate the securitization asset, the diverse consumer base paying the securitization tariff, dynamic adjustments to the tariff, and the predictability of electrical consumption. The political and regulatory risk is also an important consideration.

One similar aspect of stranded utility costs legislation across states is the provision that the state will not alter, amend, or repeal the securitization tariff paid by electric utility consumers. That pledge is a key component of the credit analysis of all stranded costs securitizations.

The inviolability of a state's pledge as a state contractual obligation is assured by both the federal and the state constitutions, under their respective contract clauses, through judicial interpretation. A state may, however, have other protections in lieu of or in addition to a contract clause.

The state and the federal courts have consistently enforced these constitutional provisions over a 60-year period. The only judicially recognized exception to the contract clause's protection is the "public calamity" doctrine, which releases the state from its contractual commitment because, in the given circumstances, it is in the citizen's best interest and that of the public welfare to do so.

Although the wording and the intent of the pledge is generally consistent across states, a "one size fits all" approach cannot be used in determining the impact of the pledge on the credit quality of a stranded utility costs transaction.

Stranded utility costs securities issued in a state with a contentious political environment and activist judicial system have a higher likelihood of experiencing challenges compared to a state with a long history of judicial and legislative stability. The pledge that a state will not alter the legislation is backed by the contract clause, but some securitization structures need additional support in the event that cash flow is stopped due to protracted legal proceedings.

In the past few years, Moody's has assigned **Aaa** ratings to stranded utility costs securitizations in three states – California, Massachusetts, and Montana, which permit the electorate to enact laws through the initiative process. The state pledge, or promise to security holders and judicial precedents in granting prompt injunctive relief if the constitutionally protected promise is breached, is a key factor in Moody's analysis of all three states. Our analysis and, in some cases, the conclusion, varied among the states.

Furthermore, the quantitative analysis of the cash flow from the tariff differs from one transaction to another, depending on several criteria including the following:

- The customer classes responsible for paying the securitization tariff (i.e., residential, small commercial and industrial, and large commercial and industrial).
- Whether shortfalls may be reallocated among all customer classes.
- The cap level, if any, imposed on the securitization tariff.
- Which type of closing date amortization schedule is involved: Would it be equal amortization, which reduces the securitization tariff over time, or mortgage style in which the securitization tariff remains flat.
- Relationship of the securitization tariff to the overall consumer bill.

Each stranded costs securitization has its unique legal, structural, and quantitative risks. In Moody's view, legislative and political risks remains a key consideration of investors. Unsuccessful challenges to electric deregulation legislation in California, Massachusetts, and Pennsylvania lessens the likelihood that a party would test the validity of the securitization tariff in those states in the near term. While the precedents have positive implications for the consumer and the investor, legislative and political risks have not disappeared from stranded costs securitizations.

In reviewing bond ratings of stranded utility costs securitizations, we evaluated the political and the legislative risks on a state-by-state basis. The evaluation included court decisions, the dynamics of state politics, and relevant legislative actions.

For example, in two Illinois securitizations, Moody's concluded that bondholders could be at risk when state (Illinois) policies on bondholder rights were unclear. However, when statutes, such as the electric deregulation laws, have been developed with unequivocal legislative intent and support, Moody's believes the state has and will continue to honor its commitment and will not impair bondholders' rights.

In the Massachusetts securitization, the political dynamics and the judicial behavior were clearer than those in some of the other states. In the fall of 1998, the voters overwhelmingly supported electric deregulation by defeating Question 4, which asked voters to overturn electric deregulation legislation. Also, the commonwealth courts have been reluctant to permit voter initiatives that impair bondholder rights, to be placed on the ballot. In contrast the California courts tend not hear cases challenging ballot initiatives until they pass, and did permit Proposition 9 to be placed before the electorate. Proposition 9 was unsuccessful.

A few years ago, Moody's estimated a total of $130 billion in nationwide stranded costs recovery. Recently, we revised the figure downward – to $10 billion – to account for approximately $102 billion we believe will be recovered through the legislative and regulatory process, as well as from higher-than-expected energy prices and proceeds from asset divestitures. As a result, Moody's has revised its estimate of the total securitization market, reducing it to $35 to $50 billion.

STATE NON-IMPAIRMENT PLEDGE AND CONTRACT CLAUSE: PROTECTION FOR INVESTORS

A review of the deregulation statutes – the basis for assessing the securitization tariff – is the first step in our analysis. The legislative provisions and regulatory framework address true sale, perfection, and nonconsolidation issues.

In addition, the legislative and regulatory structures require periodic adjustments, which will be performed at least annually, to ensure that the transaction's actual principal balance and expenses equal the schedule established at the closing date. The legislation includes provisions that permit the regulatory agencies to issue irrevocable financing orders. These two factors reduce the future regulatory risk.

An important provision in the legislation is a state pledge not to alter, amend, or repeal the securitization tariff. The statute permits a state agency to give this pledge or permits the issuer to incorporate the pledge in the financing documents. The mechanics of conveying the pledge by the state agencies in the California and Massachusetts securitizations are no stronger than those in the Illinois, Montana, and Pennsylvania securitizations or than those found in the New Jersey and Texas statutes.

However, we consider the active roles of the California and Massachusetts state agencies in the securitization process as a positive factor.

In either case, the state promise not to impair bondholders' rights is protected as a state contractual obligation by the federal and usually by the state constitutions under the contract clause. The state and federal courts have consistently enforced these constitutional provisions over a 60-year period. The only judicially recognized exception to the contract clause's protection is the "public calamity" doctrine, which releases the state from its contractual commitment because, in the given circumstances, it is in the citizen's best interest and the public welfare to do so.

Thus, the state promise cannot be defeated by a voter action, such as an initiative or referendum – considerations in the California, Massachusetts, and Montana securitizations. Nevertheless, in the event of a successful voter action in those states, we evaluated how much time it would take a state or federal court to rule that contract impairment has occurred and thus grant bondholders injunctive relief. The time could vary in each state, depending on its courts' approach to bondholder rights.

Historically, each of the three states has taken a different approach. The California courts were reluctant to interfere with the democratic process by permitting Proposition 9 to be placed before the electorate. On the other hand, Massachusetts's courts have prevented an initiative to be placed before the electorate that impaired bondholder rights. Other things being equal, Massachusetts courts have demonstrated a greater regard for bondholders' rights than the California courts.

In Montana, case law on contract impairment and initiative challenges is not as developed as in some other states because the state obligations do not include pledges (see *Exhibit 1*). As a result, Moody's determined that it might take the Montana court system (both state and federal) longer to determine that a successful initiative petition is inconsistent with the state pledge and is a violation of the state and federal contract clauses. A mitigating factor in the Montana transaction is the liquidity reserve in the structure, which could be used to make bondholder payments while the courts resolve the matter.

Exhibit 1

States that Routinely Include Pledges in Financing

	Pledge Common	Initiative State
California	Yes	Yes
Illinois	Yes	No
Massachusetts	Yes	Yes
Montana	No	Yes
New Jersey	No	No
Pennsylvania	Yes	No
Texas	No	No

Deregulation legislation is not free from challenges. In Pennsylvania, the Commonwealth court upheld the legality of the Pennsylvania Electricity Generation Customer Choice and

Competition Act of 1996 against a commerce clause challenge. The U.S. Supreme Court denied a petition for a hearing of the commerce clause claim against the Competition Act. The denial does not necessarily preclude challenges to the statutes in other states, or, for that matter, future commerce clause challenges in Pennsylvania, although the success of such a challenge is now much less likely in Pennsylvania.

IMPORTANCE OF CONSUMER BENEFITS

Moody's believes that consumers are not as likely to challenge the legislation/rate order if tangible benefits are received throughout the transaction's life. The type of benefits has varied among the different ratepayers within a state and among different states (see *Exhibit 2*). For example, retail consumers in California, Illinois, Massachusetts, New Jersey, and Pennsylvania have received rate reductions of 2.5% to 20%, compared to base rate freezes granted in Montana and Texas.[1]

Exhibit 2

Consumer Benefits

California

Utilities reduced rates for residential and small commercial customers by at least 10% beginning on January 1, 1998, and continuing through the earlier of when the utility recovers its transition costs (excluding the securitization tariff) or March 31, 2002.

Illinois

Utilities reduced residential rates 15% on August 1, 1998, and another 5% rate reduction will become effective May 1, 2002.

Massachusetts

Boston Edison Company

BECO's retail customers received an average 10% price reduction on March 1, 1998. Another inflation-adjusted 5% reduction went into effect September 1, 1999.

Montana

A two-year rate moratorium on non-gas charges beginning November 1, 1997.

New Jersey

Utilities must reduce rates by 10% to those in effect as of April 30, 1997. The rate reduction may be phased in over a 36-month period.

Pennsylvania

PECO Energy Company

On January 1, 1999, retail electric rates were reduced by 8%, which was followed by another 6% on January 1, 2000 from rates in effect at December 31, 1996. On January 1, 2001, system-wide average rates will return to 1996 levels.

PP&L, Inc.

One-year rate reduction of 4% for all customers beginning January 1, 1999 through January 1, 2000 based on rates in effect as of December 31, 1996.

West Penn Power Company

One year rate reduction of 2.5% for all customers beginning January 1, 1999 through December 31, 1999 based on rates in effect as of December 31, 1996.

Texas

Base rates are frozen through December 31, 2001 based on rates in effect as of September 1, 1999. On January 1, 2002 residential and small commercial customers (<1000kW) will receive a 6% rate reduction through January 1, 2007 from rates in effect as of January 1, 1999.

The analysis of consumer benefits is important to our analysis of the Illinois securitizations, because the stranded costs legislation contained an inseverability provision, which provides that if any aspect of the bill is declared unconstitutional the entire bill will be invalid – potentially eliminating the securitization tariff.

1 A 6% rate reduction is scheduled to be placed in effect on January 1, 2002.

The inseverability provision was included to strengthen the legislation against judicial attack after it became effective. Simply put, those parties who had a stake in the legislation benefited in some way and therefore would not be inclined to upset any provisions they considered offensive because they could lose their own "benefit of the bargain."

A pattern has emerged as the various constituencies – utilities and the consumer and small and large business advocates – entered into settlement negotiations. Residential consumer advocates have sought and obtained rate reductions and large shopping credits[2] because of the belief that residential consumers will not benefit from retail choice.

Conversely, small commercial and industrial and large commercial and industrial customers have requested and received the retention of favorable rate schedules, granted before deregulation, and an acceleration of customer choice (see *Exhibit 3*), because this aspect of deregulation benefits these groups. The amount of above-market assets recovered and allocation among the rate classes has been a contentious process in all states that have passed deregulation legislation.

Exhibit 3

Date(s) Retail Competition Effective

	Effective Date
California	January 1, 1998
Illinois	October 1, 1999 and December 31, 2000 for non-residential consumers and May 1, 2002 for residential consumers
Massachusetts	March 1, 1998
Montana	July 1, 2002 (gas)
New Jersey	August 1, 1999
Pennsylvania	January 1, 1999 – and phased in through January 2, 2000
Texas	January 1, 2002

STRANDED COSTS STRUCTURES: SIMILAR TO OTHER ABS SECURITIZATIONS

Structurally, the stranded utility costs securitizations are similar to each other. The legislation and regulatory order create a current property right to collect a future securitization tariff, more commonly known as the intangible transition property (ITP). The ITP is sold by the originating utility to either an intervening special-purpose entity or directly to the issuing trust. These entities issue public or private securities. True-sale, nonconsolidation, and perfection issues are addressed in the legislative and regulatory framework.

The legislation and financing orders require periodic adjustments, or true-ups, that will be performed at least annually, to ensure that the actual principal balance and expenses equal the amortization schedule established at the closing date.

Credit criteria for third-party servicers (suppliers) that might also be collecting the securitization tariff vary among the states (see *Exhibit 4* on the following page). Most third-party servicers must have an investment-grade rating from at least one rating agency to commingle funds. These commingling standards are aggressive for the highly rated securitization bonds. The true-up mechanism mitigates the risk by adjusting rates to cover shortfalls due to third-party servicer defaults.

2 The shopping credit is available to those customers who turn to another energy provider in a deregulated environment; if that provider's electricity generation rate is lower than the utilities, the shopping customer receives a rebate equal to the difference between the two utility's electricity rates.

Exhibit 4

Third-party Billing and Collections Criteria

California
Third-party servicers (i) or guarantor must have at least a mid-investment grade rating by any national recognized statistical rating organization, (ii) post a deposit equal to twice the maximum estimated monthly collections, or (iii) be approved by the servicer. The third-party servicer is required to pay the utility within 15 days of the invoice date, whether or not funds are remitted by end users. If the bill is not paid by the 24th day after the bill is issued, servicing reverts back to the utility.

Illinois
None- A third party servicer may (i) commingle for 7 days upon receipt from the customer or (ii) remit collected and uncollected charges by 15th day. A servicer selecting option (ii) must have at least an investment grade rating or post a deposit of at least one-month estimated billings. If the bill is not paid with in 15 days after the due date, servicing reverts back to the utility.

Massachusetts
Third-party servicers must have at least an investment grade rating from Moody's Investors Service and another rating agency or post a deposit of at least one-month estimated billing. Collected and uncollected charges must be remitted within 15 days. Dual billing commences if payment is not received by the 22nd day.

Montana
Third-party servicers must

(i) have a minimum rating of **A** by Moody's and another rating agency

(ii) have consumers send payments to a lock-box at the trust department of a bank meeting the rating requirements above, or

(iii) provide a letter of credit from a bank meeting the rating requirement above and equal to two month's estimated collections.

New Jersey
Must have an investment grade rating from either Moody's or another rating agency or maintain a deposit equal to twice the estimated charges. Payments must be remitted within 15 days or the utility may assume billing and collections by the 22nd day.

Pennsylvania
Must have an investment grade rating, post a letter of credit, or provide some other mechanism covering 30 days of collections. A third party servicer must remit collected and uncollected charges within 20-25 days. If the funds are not received within 20 days after a breach, the utility may take over servicing.

Texas
To be determined

QUANTITATIVE ANALYSIS VARIES AMONG TRANSACTIONS

The customer classes responsible for paying the securitization vary, creating unique quantitative differences among the securitizations.

Quantitative considerations include the following:

- Which customer class or classes (i.e. residential, small commercial and industrial, and large commercial and industrial) are responsible for paying the securitization tariff (see *Exhibit 5*).
- Whether shortfalls may be reallocated among all customer classes.
- Cap level, if any, imposed on the securitization tariff (see *Exhibit 6*).
- The type of closing date amortization schedule: equal amortizing, which reduces the securitization tariff over time, or mortgage style, in which the securitization tariff remains flat (see *Exhibit 7*).
- Relationship of the securitization tariff to the overall bill.

For example, the Boston Edison Company securitization contains an absolute rate cap of 3.35 cents/kWh on the securitization tariff. If the annual adjustment exceeds that amount, a cash flow shortfall could arise.

Exhibit 5
Customer Classes Paying Securitization Tariff

California
Residential and small commercial and industrial consumers (defined as 20 kWh of consumption or less). There is a separate securitization tariff for each class. A shortfall in the residential class cannot be assessed on small commercial and industrial consumers.

Illinois
All customer classes specified in financing order.

Massachusetts
All retail customers.

Montana
The gas securitization tariff is divided into two separate categories: CTC-GP and CTC-RA . The tariffs are not cross-collateralized.

Core customers, customers who converted to transportation after September 1, 1993, and those core customers that convert to transportation after December 31, 1996 are required to pay the CTC-GP. Montana Power Company's (MPC) non-core customers that converted to transportation prior to September 1, 1993 and new customers who connected to MPC's transmission and distribution system after November 1, 1991 with load growth greater than 60,000 dkt annually are not responsible for paying the GP charges. New customers connecting after December 31, 1996 with loads greater than 5,000 dkt will not be required to pay the CTC-GP.

The CTC-RA is allocated among three customer classes:

- 75% is paid by core customers, non-core customers, and new customers; new customers connecting after December 31, 1996 with consumption greater than 5,000 dkt do not have to pay the charge.
- 1% – Utilities- cities of Cut Bank, Kevin, and Sunburst.
- 24% – Non-core customers that converted to gas transportation prior to 9/1/93.

New Jersey
All retail customers.

Pennsylvania
The rate schedules will be compressed into three classes – residential, small commercial & industrial, and large commercial & industrial customers – to calculate the reconciliation. Shortfalls within a specific class may be reallocated within that class. For example, a shortfall among the residential rate schedules may be reallocated within the residential class; however, if a shortfall still exists within the residential class, it may not be reallocated among the small and large commercial and industrial classes.

Texas
Allocation among customer classes is subject to commission proceedings.

Exhibit 6
Cap Constraints

Illinois
The collection of the securitization charge is limited to the "applicable rates". The applicable rate is 1) either the bundled rate or the cost of electricity, transmission and distribution charges or 2) the unbundled rate which is the transmission and distribution charges plus the transition charge through December 31, 2006 imposed on customers that switch to alternate energy suppliers.

Shortfalls within one customer class because of the applicable rate cap will be allocated to other customer classes.

Another quantitative cap is the maximum of securitization charges and expenses that could be assessed over the transaction's life or $6.323 billion for Commonwealth Edison Company and $1.634 billion for Illinois Power Company.

Massachusetts
3.35 cents per kilowatt hour

Exhibit 6 (continued)
Cap Constraints

Pennsylvania
PECO Energy Company
The securitization tariff is limited to the sum of (1) the pre-approved annual CTC recovery rates, expressed in cents per kWh, for PECO's overall $5.26 billion stranded costs, adjusted annually for carrying costs and consumption variance; plus (2) the variable distribution charges.

PP&L, Inc.
The securitization tariff cannot exceed the generation rate cap – the sum of PP&L's pre-approved annual CTC adjusted recovery rate and PP&L's shopping credit.

West Penn Power Company
The securitization tariff cannot exceed the generation rate cap – the sum of West Penn Power's pre-approved annual CTC adjusted recovery rate and West Penn's shopping credit.
All securitization tariff shortfalls cannot be reallocated among customer classes.

Texas
The securitization tariff cannot exceed the frozen base rates through December 31, 2001 and 6% rate reduction effective January 1, 2002 through January 1, 2007.

Exhibit 7
Bond Amortization Schedules

	Amortization Schedule
California	Equal
Illinois	Equal
Massachusetts	Equal
Montana	Mortgage
New Jersey	TBD
Pennsylvania	Uneven
Texas	TBD

TBD= To be determined
Equal= The outstanding securities are repaid in equal installments

Two factors that lessen the constraint of the absolute rate cap are (1) the initial tariff is less than one-third of the cap at closing, and (2) the tariff is expected to decline by approximately 50% during the life of the transaction because the securities are equal amortizing.

The Pennsylvania securitizations are also constrained by a rate cap. Moreover, the ability to reallocate shortfalls among the various rate classes is limited to three broad categories – residential, small commercial and industrial, and large commercial and industrial. As a shortfall in the large commercial and industrial cannot be reallocated among other classes, such as the residential class, a separate analysis for each category was necessary.

CONCLUSION

Moody's has assigned **Aaa** ratings to 11 stranded cost recovery securitizations, aggregating $18 billion among five states (see *Appendix I*). The reasons for assigning the ratings has varied for each, based on our assessment of the legislative and regulatory process, judicial precedents, voter reaction, and qualitative considerations.

The legislative, political, judicial, and qualitative risks vary according to the transaction; therefore the volatility of some of the risks involved vary with each transaction.

Related Research

- Stranded Utility Costs: Legislation Jolts the Market, February 28, 1997
- California Proposition 9; Lights out for Stranded Utility Costs ABS Markets?, October 10, 1998
- Stranded Utility Costs Update: Factoring Injunctive Relief Into the Ratings Process, November 6, 1998
- Illinois Stranded Utility Costs Securitization: Are all Transactions Created Equal?, December 11, 1998
- PECO Energy Company's Stranded Costs Securitization: The Hare Crosses the Finish Line, March 26, 1999
- Boston Edison Company's Stranded Utility Costs Securitization: A Model Transaction?, July 20, 1999
- New Law in Texas Stabilizes Credit Quality, August 1999
- Smoke, Mirrors & Stranded Costs, October 11, 1999

APPENDIX I

Issuer and Sponsoring Utility	Amount($)	Issuance Date
1997		
California Infrastructure and Economic Development Bank PG&E-1	**2,901,000,000**	**Dec-97**
Pacific Gas and Electric Company		
California Infrastructure and Economic Development Bank SCE-1	**2,463,000,000**	**Dec-97**
Southern California Edison Company		
California Infrastructure and Economic Development Bank SDG&E-1	**658,000,000**	**Dec-97**
San Diego Gas & Electric Company		
Total	*6,022,000,000*	
1998		
ComEd Transitional Funding Trust	**3,400,000,000**	**Dec-98**
Commonwealth Edison Company		
Illinois Power Special Purpose Trust	**864,000,000**	**Dec-98**
Illinois Power Company		
MPC Natural Gas Funding Trust	**62,700,000**	**Dec-98**
Montana Power Company		
Total	*4,326,700,000*	
1999		
PECO Energy Transition Energy Trust	**4,000,000,000**	**Mar-99**
PECO Energy Company		
California Infrastructure and Economic Development Bank SPPC-1	**24,000,000**	**Apr-99**
Sierra Pacific Power Company		
Massachusetts RRB Special Purpose Trust BEC-1	**725,000,000**	**Jul-99**
Boston Edison Company		
PP&L Transition Bond Company LLC	**2,420,000,000**	**Aug-99**
PP&L, Inc.		
West Penn Funding LLC	**600,000,000**	**Nov-99**
West Penn Power Company		
Total	*7,769,000,000*	
Total Issuance	**18,117,700,000**	

Record Request AG-2 (Tr. 1, at 45-46)

Would the Companies be opposed to the inclusion of a term in the findings and order of the Department that any miscalculations to the issuance advice letter will be corrected as soon as possible and that the adjustment to the customers' rates will also be made accordingly?

Response

The Companies would not be opposed to a requirement to the effect that any miscalculations in a routine True-Up Advice Letter will be promptly corrected by the filing of a revised True-Up Advice Letter and that appropriate changes in the RTC Charge will be made upon effectiveness of the routine issuance advice letter. However, in order to avoid changes in the draft financing order, the Companies would agree to include such provision in the Servicing Agreements. The Companies propose to include the following additional language in the Servicing Agreements (as indicated in bold print):

> Routine Periodic Adjustments. The Servicer shall file a Routine True-Up Letter at least 15 days before the end of any calendar quarter or Payment Date at such times as it may reasonably determine to meet the Required Debt Service for the then current Remittance Period , provided, however, that the Servicer shall file a Routine True-Up Letter on or before August 15 in each year commencing August 15, 2013, until the Retirement of the Notes. **In the event that any Routine Anniversary True-Up Letter or Routine True-Up Letter contains a miscalculation or other error that affects the RTC Charge, the Servicer will promptly file a revised Routine true-Up Advice Letter.**

Record Request AG-3 (Tr. 1, at 46)

Provide the full package of the original issuance advice letter dated July 1999 for the initial Boston Edison securitization.

Response

Please see Attachment RR-AG-3, the original issuance advice letter dated July 28, 1999 for the initial Boston Edison securitization.

ISSUANCE ADVICE LETTER

July 28, 1999

ADVICE DTE 98-118

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY (THE "DEPARTMENT") OF THE COMMONWEALTH OF MASSACHUSETTS

SUBJECT: Issuance Advice Letter for Electric Rate Reduction Bonds ("RRBs") Pursuant to DTE Docket No. 98-118 (the "Financing Order"), Boston Edison Company ("Boston Edison") hereby transmits for filing, on or about the pricing date of this series of RRBs, the initial RTC Charge for such series. This Issuance Advice Letter is for the RRB series Massachusetts RRB Special Purpose Trust BEC-1 Rate Reduction Certificates classes A-1, A-2, A-3, A-4 and A-5. Any capitalized terms not defined herein shall have the meanings ascribed thereto in the Financing Order.

PURPOSE

This filing establishes the following:

(a) the actual terms of the RRBs being issued;
(b) confirmation of ratepayer savings;
(c) the initial RTC Charge for retail users;
(d) the identification of the Transition Property to be sold to a special purpose entity (the "SPE"); and
(e) the identification of the SPE;

BACKGROUND

In the Financing Order, the Department authorized Boston Edison to file an Issuance Advice Letter when pricing terms for a series of RRBs have been established. This Issuance Advice Letter filing incorporates the methodology for determining the RTC Charge approved and authorized by the Department in the Financing Order to establish the initial RTC Charge for a series of RRBs and establishes the initial RTC Charge to be assessed and collected from all classes of retail users of Boston Edison's distribution system within the geographic service territory as in effect on July 1, 1997, whether or not energy is purchased from Boston Edison or any TPS, and whether or not such distribution system is being operated by Boston Edison or a successor distribution company. The RTC Charge is a portion, which may become all, of the transition charge approved by the Department. The RTC Charge is a usage-based component of the transition charge on each retail user's monthly bill, and may include in the future a component of any exit fee collected pursuant to M.G.L. c. 164, § 1G(g) until the Total RRB Payment Requirements are discharged in full.

ACTUAL TERMS OF ISSUANCE

RRB Name:	Massachusetts RRB Special Purpose Trust BEC-1 Rate Reduction Certificates
RRB Issuer:	Massachusetts RRB Special Purpose Trust BEC-1
Trustee(s):	The Bank of New York, as Note Trustee and Certificate Trustee; The Bank of New York (Delaware), as Delaware Trustee
Closing Date:	July 29, 1999
Bond Ratings:	Aaa/AAA/AAA/AAA (Moody's/S&P/Fitch IBCA/Duff & Phelps)
Amount Issued:	$725,000,000
Transaction costs of issuance:	See Attachment 1
Ongoing transaction costs:	See Attachment 2
Coupon Rate(s):	Class A-1: 5.99%; Class A-2: 6.45%; Class A-3: 6.62%; Class A-4: 6.91%; Class A-5: 7.03%
Call Features:	5% cleanup call only
Massachusetts Tax Exempt (yes/no):	Personal income tax exempt only
Expected Principal Amortization Schedule:	See Attachment 3
Expected Final Maturity:	Class A-1: 3/15/2001; Class A-2: 9/15/2003; Class A-3: 3/15/2005; Class A-4: 9/15/2007; Class A-5: 3/15/2010
Legal Final Maturity:	Class A-1: 3/15/2003; Class A-2: 9/15/2005; Class A-3: 3/15/2007; Class A-4: 9/15/2009; Class A-5: 3/15/2012
Distributions to Investors (quarterly or semi-annually):	Semi-Annually
Annual Servicing Fee as a percent of initial RRB principal balance:	0.05%
Overcollateralization amount for the RRBs:	0.50% of initial RRB principal balance, or $3,625,000

Confirmation of Ratepayer Savings

The Financing Order requires Boston Edison to demonstrate, using the savings methodology approved in that Docket, that the actual terms of the RRB Transaction result in net savings. Attached to this Issuance Advice Letter is a spreadsheet calculation which shows expected net savings of approximately $76 million for this series of RRBs. See Attachment 4.

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Initial RTC Charge

Table I below shows the current assumptions for each of the variables used in the initial RTC Charge calculation.

TABLE I
INPUT VALUES FOR RTC CHARGES

Forecasted retail kWh sales expected to be realized in current period: (net of estimated charge-offs)	6,441,583,026
Percent of billed amounts expected to be charged-off:	0.67% per annum
Weighted average days sales outstanding: (calculated as follows)	45
Percent of billed amounts collected in current month:	0.00%
Percent of billed amounts collected in second month after billing:	49.67%
Percent of billed amounts collected in third month after billing:	49.67%
Percent of billed amounts collected in fourth month after billing:	0.00%
Percent of billed amounts collected in fifth month after billing:	0.00%
Forecasted annual ongoing transaction expenses*:	$365,681
Required annual overcollateralization amount:	$329,545
Required Interest Payments:	$30,271,829
Current RRB outstanding balance:	$725,000,000
Expected RRB outstanding balance as of March 15, 2000:	$685,000,000

The initial RTC Charge calculated for retail users is as follows: 1.1017 ¢/kWh

Transition Property

Transition Property is the property described in M.G.L. c. 164, § 1H(a) relating to the RTC Charge set forth herein, including, without limitation, the right, title, and interest in and to all revenues, collections, claims, payments, money, or proceeds of or arising from or constituting (a) the reimbursable transition costs amounts established by the Financing Order including such amounts established in the Issuance Advice Letter, (b) the RTC Charge authorized by the Financing Order including the initial RTC Charge set forth in the Issuance Advice Letter, as may be adjusted from time to time in order to generate amounts sufficient to discharge the Total RRB Payment Requirements, and (c) all rights to obtain periodic adjustments and non-routine adjustments to the RTC Charge.

This RTC Charge, as adjusted from time to time, shall remain in place until the Total RRB Payment Requirements are discharged in full.

* Ongoing transaction expenses pro-rated for the initial interest period, which begins on the closing date (7/29/1999) and ends on the first payment date (3/15/2000).

IDENTIFICATION OF SPE

The owner of the Transition Property (the "SPE") will be: BEC Funding LLC. The SPE shall be considered a financing entity for purposes of M.G.L. c.164, § 1H.

EFFECTIVE DATE

In accordance with the Financing Order, the RTC Charge shall be automatically effective when filed by means of this Issuance Advice Letter and will continue to be effective, unless it is changed by a Routine True-Up Letter or a Non Routine True-Up Letter.

NOTICE

Copies of this filing are being furnished to the parties on the attached service list. Notice to the public is hereby given by filing and keeping this filing open for public inspection at the Company's corporate headquarters.

Enclosures

ATTACHMENT 1
TRANSACTION COSTS OF ISSUANCE

	Amount
Underwriting spread	$3,066,750
Financial Advisory Fee	275,000
Rating agency fees	510,000
Accounting fees	75,000
SEC registration fee (.0278%)	201,550
DTE filing fee ($750 for first million plus $150 for each additional million)	110,100
Printing and marketing expenses	375,000
Trustee fees and counsel	60,000
Company legal fees and expenses	2,000,000
Underwriters' legal fees and expenses	425,000
Bond counsel legal fees and expenses	425,000
MassDevelopment/HEFA fees	145,000
Servicing set-up costs	450,000
SPE set-up costs	25,000
Miscellaneous costs	100,000
Expenses in connection with reducing capitalization (including call provisions and prepayments)	26,000,000
Total transaction costs of issuance	$34,243,400*

* Does not include original issue discount of $244,860.

ATTACHMENT 2
ONGOING TRANSACTION COSTS (ANNUAL)

Ongoing Costs	Amount
Administration fee	$ 75,000
Rating agency fees	20,000
Accounting, legal and trustees' fees	75,000
Servicing fee (.05% of initial principal balance)[1]	362,500
Overcollateralization amount	329,545
Miscellaneous[2]	50,000
Total estimated costs	$912,045

[1] These costs will include:
- Billing, collecting and remitting the RTC Charges;
- Calculate daily amount of remittances to the SPE trustee;
- Wire transfer daily remittances to the SPE trustee;
- Prepare monthly servicer report for trustee and rating agencies;
- Prepare semi-annual servicer report for trustee;
- Manage and invest the various SPE cash accounts;
- Reflect all transactions on the financial statements;
- Perform periodic reconciliations with the trustee;
- Perform annual true-up and adjust RTC Charge, as necessary; and
- Maintain memorandum account, if any.

[2] These costs would include any contingent liabilities arising in connection with indemnity provisions in the RRB Transaction documents.

ATTACHMENT 3
EXPECTED AMORTIZATION SCHEDULE

te	A-1 Principal Balance	A-2 Principal Balance	A-3 Principal Balance	A-4 Principal Balance	A-5 Principal Balance	Total Outstanding Principal Balance
-Jul-99	$108,500,000	$170,609,837	$103,390,163	$170,875,702	$171,624,298	$725,000,000
Mar-00	68,500,000	170,609,837	103,390,163	170,875,702	171,624,298	685,000,000
Sep-00	30,058,542	170,609,837	103,390,163	170,875,702	171,624,298	646,558,542
Mar-01	0	170,609,837	103,390,163	170,875,702	171,624,298	616,500,000
Sep-01	0	138,240,115	103,390,163	170,875,702	171,624,298	584,130,278
Mar-02	0	102,109,837	103,390,163	170,875,702	171,624,298	548,000,000
Sep-02	0	68,014,173	103,390,163	170,875,702	171,624,298	513,904,336
Mar-03	0	33,609,837	103,390,163	170,875,702	171,624,298	479,500,000
Sep-03	0	0	103,390,163	170,875,702	171,624,298	445,890,163
Mar-04	0	0	68,500,000	170,875,702	171,624,298	411,000,000
Sep-04	0	0	34,649,752	170,875,702	171,624,298	377,149,752
Mar-05	0	0	0	170,875,702	171,624,298	342,500,000
Sep-05	0	0	0	137,123,948	171,624,298	308,748,246
Mar-06	0	0	0	102,375,702	171,624,298	274,000,000
Sep-06	0	0	0	68,519,879	171,624,298	240,144,177
Mar-07	0	0	0	33,875,702	171,624,298	205,500,000
Sep-07	0	0	0	0	171,624,298	171,624,298
Mar-08	0	0	0	0	137,000,000	137,000,000
Sep-08	0	0	0	0	103,134,628	103,134,628
-Mar-09	0	0	0	0	68,500,000	68,500,000
-Sep-09	0	0	0	0	34,631,016	34,631,016
-Mar-10	0	0	0	0	0	0

Boston Edison Company
Summary of Transition Charge
Fixed Component — Pilgrim Sale - 7/13/99 Closing
$ In Millions

Attachment GOL-4R4
Page 2 of 11

Securitization Filing
Schedule BE-4A

Line #	Year Col. A		Pre-Tax Return on Generation Related Investment & Regulatory Assets Col. B	Amortization of Generation Related Investment & Regulatory Assets Col. C	Transmission in Support of Remote Generating Assets Col. D	Base Total Fixed Component Col. E	Adjustment for Residual Value Credit Col. F	Net Fixed Component Including Adj. for Residual Value Credit Col. G	Securitized Cash Flow at 7.94% Col. H	Securitized Net Fixed Component Including Adj. for Residual Value Credit Col. I	Prior RVC Col. J	PRVC Col. K	Securization Principal Col. L	Amort. Col. M	Interest Col. N	Securitization Savings NPV @ 7.94% $ 76 Col. O
						(Cols. B+C+D)	(Col. J + Col. K)	(Col. E + Col. F)	(Col. M + Col. N)	(Col. G 1998 - 7/31/99, Col. H 8/1/99 - 2009, Col. G. 2010 - 2016)						(Col. G - Col. H)
1	1998		$ 86	$ 121	$ 1	$ 208	($62)	$ 146		$ 146						
2	1999	1/1 thru 7/28	42	69		111	(33)	78		78	(33)		691			
2a	1999	7/29 thru 12/31	30	49		80	(8)	72	50	50	(24)	18	683	28	22	22
3	2000		63	138		201	(22)	179	117	117	(57)	35	597	66	50	62
4	2001		54	82		136	(22)	114	111	111	(57)	35	530	66	45	3
5	2002		48	82		130	(22)	108	106	106	(57)	35	464	66	40	2
6	2003		42	82		123	(22)	101	101	101	(57)	35	398	66	34	1
7	2004		35	82		117	(22)	95	95	95	(57)	35	332	66	29	(1)
8	2005		29	82		111	(22)	89	90	90	(57)	35	265	66	24	(1)
9	2006		23	82		105	(22)	83	85	85	(57)	35	199	66	19	(2)
10	2007		17	82		99	(22)	77	80	80	(57)	35	133	66	13	(3)
11	2008		11	82		93	(22)	71	74	74	(57)	35	66	66	8	(3)
12	2009		6	82		87	(22)	65	69	69	(57)	35	0	66	3	(4)
13	2010					-	-	-		-	-					
14	2011					-	-	-		-	-					
15	2012					-	-	-		-						
16	2013					-	-	-		-						
17	2014					-	-	-		-						
18	2015					-	-	-		-						
19	2016					-	-	-		-						
20	2017									-						
		Total Amortization		1,112												

This is the NPV of Column G from line 2a onwards discounted at 10.88%

Potential Balance to be Securitized	$702.6
Actual Amount Securitized on 7/29/99	690.7
Amt to be recovered in Variable Component	$11.9
Check	$690.7 — 7.94%

Net Present Value of Securitization Savings @ 7.94% - Pilgrim only	$ 70.5
Net Present Value of Securitization Savings @ 7.94% - L'Energia only	$ 5.3
Net Present Value of Total Securitization Savings @ 7.94%	$ 75.8

Legend:

Col. B	per Settlement Attachment 3 at Page 242, Col. B
Col. C	per Settlement Attachment 3 at Page 242, Col. C
Col. D	per Settlement Attachment 3 at Page 242, Col. D
Col. J	per Transition Charge True-up
Col. K	per GOL-3R3, Page 7 of 11 Col. D

Actual Market Valuation will be credited in Reconciliation Account

Note: Numbers may not foot due to rounding
The Securitization Principal, Amortization, and Interest schedule (Cols. L, M, & N) is provided for illustrative purposes.
The final amounts will vary due to the assumptions listed in Exhibit BE-3 on page 17.

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Record Request DTE-1 (Tr. 1, at 11)

Provide a corrected version of Exhibit DTE-1-8, Attachment DTE-1-8 **(CONFIDENTIAL)**.

Response

[CONFIDENTIAL ATTACHMENTS]

Please see Attachment RR-DTE-1 **(CONFIDENTIAL)** for an updated and corrected version of Exhibit DTE-1-8, Attachment DTE-1-8 **(CONFIDENTIAL).**

Record Request DTE-2 (Tr. 1, at 86)

Provide an updated version of Exhibit NSTAR-GOL-1 **(CONFIDENTIAL)** that incorporates all updates, and include a copy of the exhibit pages that are cross-referenced in the updated version of Exhibit NSTAR-GOL-1 **(CONFIDENTIAL)**.

Response

[CONFIDENTIAL ATTACHMENTS]

Please see Attachment RR-DTE-2 **(CONFIDENTIAL)** for an updated version of Exhibit NSTAR-GOL-1 **(CONFIDENTIAL)** with exhibit pages from other proceedings that are cross-referenced.

Record Request DTE-3 (Tr. 1, at 93-95)

Provide Department docket numbers in which it approved:

(a) the four elements referenced in Exhibit NSTAR-GOL, page 6, lines 14-16; and

(b) all elements of the Commonwealth deferral amount that Commonwealth seeks to securitize.

Response

(a) As discussed in Exhibit NSTAR-GOL, page 6, Lines 14-16, Commonwealth has requested approval to securitize the remaining fixed component of the access charge and the incentive mitigation from the prior PPA buyouts of Lowell, Pilgrim and Seabrook. These recoveries of transition costs were approved by the Department in the following dockets:

Lowell	D.T.E. 99-69
Pilgrim	D.P.U./D.T.E. 98-119/126
Seabrook	D.T.E. 02-34

(b) Please see the Companies' response to Record Request DTE-6.

Record Request DTE-4 (Tr. 1, at 112-113)

Provide a summary of the changes identified in Exhibit AG-1-1, including, specifically, the changes set forth on page A-37.

Response

The following is a summary the changes made in the proposed Financing Order (Exhibit NSTAR-1-B) compared to the Financing Order issued by the Department in D.T.E. 98-118:

- Two utilities and SPEs involved rather than one (changes reflected throughout);
- Different transition costs being securitized and related calculation of customer savings (e.g., pgs 1-3, and A-12 through A-16);
- Added clarification relating to the relationship between the debt securities issued by the SPEs and the rate reduction certificates issued by the trust established by the state agencies (e.g., pgs A-8 through A-9);
- That each utility will sell its transition property to only one SPE (thus removing the possibility of multiple SPEs used by each distribution company) (e.g., pgs A-26 and A-37);
- Clarification of the rights of the note trustees to enforce that statutory lien created by G.L. c. 164, §1H(e) (e.g., pg A-25);
- Explained required amendments to outstanding Commonwealth debt documents and associated consent fees (e.g., pgs A-13 through A-14);
- Different use of proceeds (e.g., pgs A-80 through A-81);
- Reliance on generally applicable IRS Revenue Procedure published in 2000 rather than individually obtained IRS private letter rulings (e.g., pgs A-29 through A-30);
- Clarified mechanics of the various subaccounts of the Collection Account (e.g., pgs A-33 through A-35);
- Description of mechanics for sharing any shortfalls in transition charge collections between the RTC Charge associated with Boston Edison's 1999 RRB transaction and the RTC Charge associated with the currently proposed transaction (e.g., pgs A-36 through A-37);

- Elimination of provisions related to the divestiture of Pilgrim Station (e.g., pgs A-28, A-42 and A-49 through A-50); and
- Non-substantive language clean-up.

Record Request DTE-6 (Tr. 1, at 169-172)

Provide a breakdown of the costs included in the Commonwealth Deferral, which is requested to be securitized, and whether and how the recovery of those costs were approved by the Department.

Response

Commonwealth has requested approval to securitize its deferred transition costs balance at the time the Companies issue the RRBs through the RTC Charge. G.L. c. 164, §1H(b)(1) provides that the Department may issue financing orders to provide for the recovery of transition costs. Section 1H(a) defines transition costs as "costs determined pursuant to section 1G."

The types of costs that Commonwealth is recovering through the transition charge are described in Exhibit NSTAR-COM-GOL-4, at page 4 of 16. The Department approved Commonwealth's Restructuring Plan in D.P.U./D.T.E. 97-111 and 97-111-A. In that proceeding, the Department found that each of the types of costs claimed by Commonwealth as transition costs in its Restructuring Plan, and which are described in Exhibit NSTAR-COM-GOL-4, page 4 of 16, are those types for which G.L. c. 164, § 1G allows recovery. D.P.U./D.T.E. 97-111 at 61.

In recognition of the need to achieve statutorily required rate reductions, the Department authorized Commonwealth to defer the amount by which, in any given period, Commonwealth's actual transition charges exceed the transition charges actually collected during that period. D.P.U./D.T.E. 97-111 at 37. As described above, each item of transition cost being recovery by Commonwealth, and, therefore, constituting part of the deferral balance, has been previously approved by the Department. However, as all cost accruals and related cash collections are fungible, it is impossible at any given moment to determine the exact transition costs that constitute the deferral balance. The best illustration of this point is a bucket filled with multi-colored fluids. The multi-colored fluids represent approved transition costs. As the colored fluids (approved transition costs) are poured into the bucket, the resulting liquid becomes a single color (for example, blue). As the company recovers its transition costs from customers, blue fluid is drained out of the bucket (the recovered transition costs). It is impossible to identify which fluids (transition costs) are being drained (recovered in rates), or which fluids remain in the bucket (the deferral balance that is yet to be recovered). However, we know that all fluids in the bucket represent approved transitions costs, and that approved transition costs are eligible to be securitized.

The next step is to determine whether the amount of these approved transition costs have been approved by the Department, or are subject to a process assuring that the amounts are subject to approval of the Department, with appropriate adjustments to rates in the event that the amount poured into the bucket exceeds amounts approved by the Department. Through the year 2002, the Department has reviewed and approved the reconciliation of costs and revenues (and the resulting level of deferrals) in the annual reconciliation filings made by Commonwealth in compliance with its Department-approved Restructuring Plan. The Department's approval of a settlement agreement regarding Commonwealth's 2002 reconciliation established the amount of the transition cost deferral at the end of calendar year 2002. D.T.E. 02-80B (2004). That amount ($81.510 million) represents the cumulative level of deferrals remaining from all past years and is set forth in this proceeding in Exhibit NSTAR-COM-GOL-3) represents the cumulative level of deferrals remaining from all past years and is set forth in this proceeding in Exhibit NSTAR-GOL-3. The review and approval of the reconciliation of transition costs and revenues in previous years were in the following dockets: D.T.E. 99-90, D.T.E. 00-83 and D.T.E. 01-79.

The reconciliation of the amount of transition costs being recovered or expected to be recovered by Commonwealth during 2003 and 2004 have not yet to be approved by the Department. However, these costs are subject to a process to assure that the Department reviews and approves these costs, and that appropriate adjustment to rates are made in the event that a company over- or undercollects these transition charges. G.L. c. 164, § 1G(a)(2) provides that the Department may, at an electric company's expense, audit, review and reconcile the difference, if any, between assumed reimbursable transition costs amounts and the actual reimbursable transition costs amounts, not less often than once during each 18-month period following the effective date of the Financing Order.

The restructuring statute also expressly contemplates that rate reduction bonds may be issued against estimated transition costs. G.L. c. 164, § 1G(a)(2) states that the Department shall review a financing order periodically, at a minimum not less than every 18 months from the inception of the original order, to determine if the amount of estimated reimbursable transition costs amounts proved to be accurate. To the extent reimbursable transition costs amounts previously included in a financing order exceed the correct amount, the electric company must provide customers with a uniform rate credit through the mechanism of their annual transition charge update. As provided in G.L. c. 164 § 1G(a)(2), any uniform rate credit resulting from an audit will not diminish the right of the electric company to collect RTC Charges as the same come due. This provision protects the status of the transfer of the Transition Property as a true sale (as described in Exhibit NSTAR-JF) and assures that it will not reduce or impair the value of the Transition Property. Accordingly, G.L. c. 164, §1G(a)(2) clearly contemplates the issuance of rate reduction bonds against estimated transition costs and contains a mechanism for Department review of the amount of those costs and an adjustment in the event that the assumed transition costs exceed actual, approved, transition costs.

Record Request DTE-7 (Tr. 1, at 200-201)

Referring to Exhibit NSTAR-EGO at pages 5-6, further define the SPEs' rights to shut off electric power.

Response

Shut-off policies are viewed by rating agencies as an important tool for inducing prompt payment from customers and for limiting losses from uncollectible bills. As described in Exhibit NSTAR-EGO, the proposal would place the Sellers, as Servicers, in the same legal position as the distribution companies, i.e., they would be entitled to utilize shut-off policies to the extent permitted by G.L. c. 164, §§ 116, 124-124I and applicable regulations. In the event of any amendment or change to existing shut-off policies, the Sellers, as Servicer, would be required to comply with any then current laws, rules and regulations.